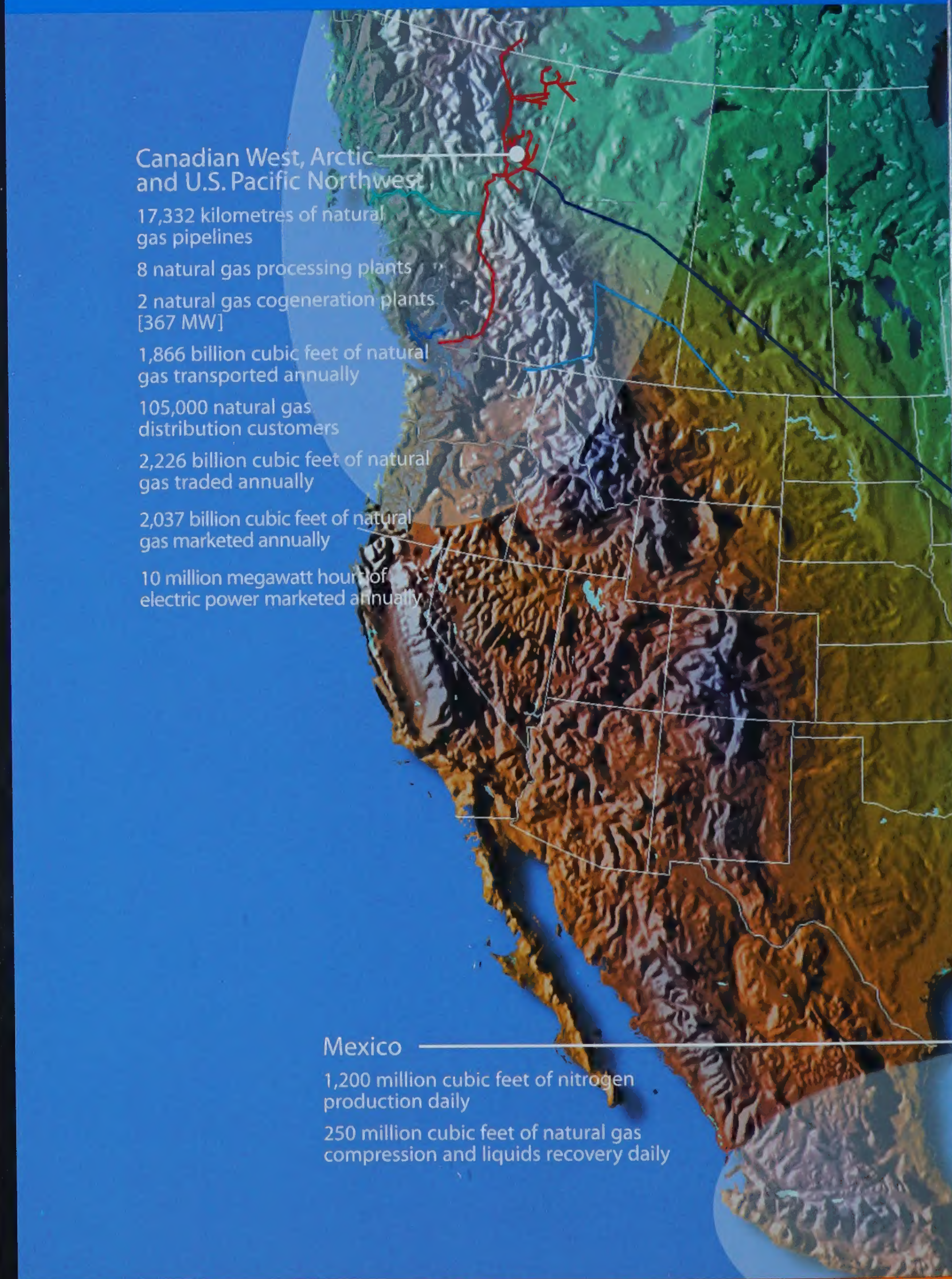
Westcoast Energy Inc.

ANNUAL REPORT 1999

Building for the Future

BUILDING FOR THE FUTURE: A NORTH AME

A component of Westcoast Energy's corporate goal – to becom companies by providing superior energy services value to its activities in four geographic areas where the Company has sign



Canadian West, Arctic and U.S. Pacific Northwest

BC Pipeline and Field Services Divisions [100%]
Centra Gas British Columbia [100%]
Island Cogeneration Project [100%]
Pacific Northern Gas [41%/100% of voting shares]
Westcoast Gas Services [100%]
Engage Energy [50%]
Foothills Pipe Lines [50%]
McMahon Cogeneration Plant [50%]
Sulphur Products [50%]
NGX Canada [49%]
NrG Information Services [33%]
Alliance Pipeline [23.6%]

Ontario and U.S. Great Lakes

Union Gas [100%]
Union Energy [100%]
Enlogix [100%]
Ford Cogeneration Plant [100%]
Fort Frances Cogeneration Plant [100%]
St. Clair Pipelines (1996) [100%]
Westcoast Capital [100%]
Empire State Pipeline [50%]
Lake Superior Cogeneration Plant [50%]
Whitby Cogeneration Plant [50%]
Vector Pipeline [30%]
Millennium West Pipeline Project [100%]
Millennium Pipeline Project [21%]

Atlantic C and Nort

Bayside Powe
Maritimes & N

AN FOOTPRINT

of the few big North American energy
mers – is to increase the density of its
t assets and market presence.

.S.

100%]

Pipeline [37.5%]

Mexico

Campeche Natural Gas Compression Services Project [45%]

Cantarell Nitrogen Project [20%]

Legend

- BC Pipeline and Field Services Divisions
- Pacific Northern Gas Pipeline
- Centra Gas BC Transmission Pipeline
- Foothills Pipe Lines
- Alliance Pipeline
- Union Gas Transmission Pipeline
- Empire State Pipeline
- Vector Pipeline
- Maritimes & Northeast Pipeline
- Cantarell Nitrogen Project Pipeline

Proposed Projects

- Millennium West Pipeline Project
- Millennium Pipeline Project

Canadian West, Arctic and U.S. Pacific Northwe

Westcoast Energy began operating British Columbia's fi natural gas mainline pipeline in 1957. Today, the Company natural gas gathering pipelines, processing facilities an transmission systems connect natural gas supply in northea British Columbia, northwest Alberta, the Yukon, and th Northwest Territories with markets in Western Canada an the United States Pacific Northwest. Natural gas fuels coge eration facilities that provide electric power to Britis Columbia's industrial customers, and is transported and di tributed to consumers on the British Columbia North Coa and Vancouver Island through the Company's Pacif Northern Gas and Centra Gas British Columbia subsidiarie Westcoast Energy is committed to maximizing the value these existing assets through its participation in new industr activity in the southern Northwest Territories. The Allian Pipeline, expected to begin service in late 2000, will exten the market scope for Western Canadian natural gas suppl and further integrate the North American energy industry.

Ontario and U.S. Great Lakes

Through more than 34,000 kilometres of natural g transmission and distribution pipelines, Westcoa Energy's Union Gas subsidiary delivers energy to more tha one million Ontario natural gas consumers. Wi Canada's largest underground storage facilities, the Uni Gas Dawn hub provides transportation and storage servi to utilities and other industry participants in the natural g markets of Ontario, Quebec, and the central and easte United States, and is the strategic link in the Company's pr posed west-to-east energy corridor from British Columbia New York. Westcoast Energy also owns, or is a partner in, fo cogeneration plants producing electric power for ma industrial customers in Ontario. The Company's ener services businesses act as a key conduit of custom knowledge, offering the opportunity to move Westco Energy's market presence beyond natural gas transportati and distribution.

Atlantic Canada and Northeast U.S.

Construction of the Maritimes & Northeast Pipeli launched a new energy industry in Atlantic Canada. With t addition of lateral pipelines to serve industries and consum in Nova Scotia and New Brunswick, Westcoast Energy w remain a key player in the expansion of the natural g transportation business on Canada's East Coast. T Company will maximize the value of its assets Atlantic Canada through the development of electric po generation facilities that can be fuelled by natural gas from Maritimes & Northeast Pipeline.

Mexico

As Mexico becomes fully integrated into the North American energy economy, Westcoast Energy plans to extend its continental reach through its partnership in infrastructure projects with the opportunity for substantial returns. As an energy industry leader, the Company is a partner of choice for projects requiring expert knowledge of natural gas gathering, processing, transportation, distribution, and electric power generation.

The Year: Pipeline Expansion

During five short months of 1999, Westcoast Energy built the 568-kilometre Canadian portion of the Maritimes & Northeast Pipeline. The cover photo for this Annual Report was captured on the mainline pipeline construction right-of-way in Nova Scotia.

Now in operation, the 1,051-kilometre mainline pipeline transports natural gas from Goldboro, Nova Scotia, to markets in Atlantic Canada and New England.

The Maritimes & Northeast Pipeline is an integral part of a new energy initiative on Canada's East Coast, opening a new natural gas supply basin in the Atlantic and bringing natural gas to the Maritimes for the first time.

Corporate Profile

Westcoast Energy Inc. is a leader in the North American energy industry. Natural gas, a clean-burning, economical and plentiful energy source, is the foundation of the Company's operations and Westcoast Energy's fuel of choice to provide superior energy services value to its customers.

Headquartered in Vancouver, British Columbia, Westcoast Energy operates a $12-billion network of natural gas gathering, processing, transportation, storage and distribution assets, and related electric power generation, international, financial, information technology and energy services businesses.

Building for the Future

More than 40 years ago, the Company built Canada's first "big-inch" pipeline from northeast British Columbia to the Canada-United States border, bringing natural gas supply from the Western Canadian Sedimentary Basin to emerging markets in British Columbia and the United States Pacific Northwest.

Today, with operations across North America, the Company remains committed to **building for the future**. In 2000, Westcoast Energy, with its partners, will complete the Alliance and Vector pipelines to transport Western Canadian natural gas to growing Canadian and United States markets.

Annual Meeting

The Annual Meeting of Shareholders of Westcoast Energy Inc. will be held in the Robson Square Conference Centre in Vancouver, British Columbia, on Wednesday, April 26, 2000, 11:00 a.m. (Local time).

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Canadian West, Arctic and U.S. Pacific Northwest

Westcoast Energy began operating British Columbia's first natural gas mainline pipeline in 1957. Today, the Company's natural gas gathering pipelines, processing facilities and transmission systems connect natural gas supply in northeast British Columbia, northwest Alberta, the Yukon, and the Northwest Territories with markets in Western Canada and the United States Pacific Northwest. Natural gas fuels cogeneration facilities that provide electric power to British Columbia's industrial customers, and is transported and distributed to consumers on the British Columbia North Coast and Vancouver Island through the Company's Pacific Northern Gas and Centra Gas British Columbia subsidiaries. Westcoast Energy is committed to maximizing the value of these existing assets through its participation in new industry activity in the southern Northwest Territories. The Alliance Pipeline, expected to begin service in late 2000, will extend the market scope for Western Canadian natural gas supply, and further integrate the North American energy industry.

Ontario and U.S. Great Lakes

Through more than 34,000 kilometres of natural gas transmission and distribution pipelines, Westcoast Energy's Union Gas subsidiary delivers energy to more than one million Ontario natural gas consumers. With Canada's largest underground storage facilities, the Union Gas Dawn hub provides transportation and storage services to utilities and other industry participants in the natural gas markets of Ontario, Quebec, and the central and eastern United States, and is the strategic link in the Company's proposed west-to-east energy corridor from British Columbia to New York. Westcoast Energy also owns, or is a partner in, four cogeneration plants producing electric power for major industrial customers in Ontario. The Company's energy services businesses act as a key conduit of customer knowledge, offering the opportunity to move Westcoast Energy's market presence beyond natural gas transportation and distribution.

Atlantic Canada and Northeast U.S.

Construction of the Maritimes & Northeast Pipeline launched a new energy industry in Atlantic Canada. With the addition of lateral pipelines to serve industries and consumers in Nova Scotia and New Brunswick, Westcoast Energy will remain a key player in the expansion of the natural gas transportation business on Canada's East Coast. The Company will maximize the value of its assets in Atlantic Canada through the development of electric power generation facilities that can be fuelled by natural gas from the Maritimes & Northeast Pipeline.

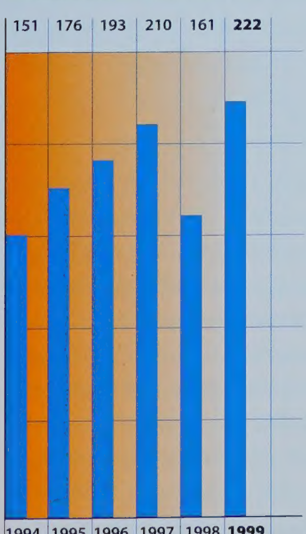
Mexico

As Mexico becomes fully integrated into the North American energy economy, Westcoast Energy plans to extend its continental reach through its partnership in infrastructure projects with the opportunity for substantial returns. As an energy industry leader, the Company is a partner of choice for projects requiring expert knowledge of natural gas gathering, processing, transportation, distribution, and electric power generation.

Financial Summary

- Net income applicable to common shares was $222 million in 1999, $61 million higher than in 1998. This performance was influenced by two divestitures, by colder weather compared with 1998, and by a number of unusual items relating primarily to the Company's retail energy services business.
- On a weather-normalized basis, after eliminating the effect of divestitures and unusual items, 1999 earnings per common share totalled $1.92, compared with $2.01 in 1998. Operating losses incurred in the retail energy services business offset the positive performance of the transmission and field services businesses.
- In 1999, capital expenditures and investments totalled approximately $1.5 billion. This represents the peak year of a three-year, $4-billion capital expansion program. Capital expenditures for 2000, the final year of this program, are budgeted to total approximately $1.3 billion.
- During 1999, the Company completed two public offerings of preferred shares. The proceeds from these share issues, totalling approximately $275 million, strengthen the Company's equity base in support of its ongoing capital expansion program.
- During 1999, the Company paid common share dividends totalling $1.28 per share, compared with $1.26 in 1998.
- During 1999, Westcoast Energy's common share price declined from $30.50 to $23.15 (TSE). This decline in the Company's common share price, combined with an annual common share dividend of $1.28, resulted in a total 1999 common shareholder return of approximately -20%. The Toronto Stock Exchange Pipelines Sub-Index, the Company's industry peer group, recorded a total return of approximately -28%. These weak performances reflect, to a large extent, the movement of significant investment capital from the interest-sensitive sector – in which the Company and its peers are included – to other sectors such as high technology.

For the years ended December 31 ($million)	**1999**	1998	1997
FINANCIAL			
Operating revenues	**6,265**	7,376	7,312
Net income	**267**	198	238
Net income applicable to common shares	**222**	161	210
Operating cash flow	**499**	448	522
Total assets	**11,777**	10,820	10,075
Per common share (dollars)			
— Earnings	**1.95**	1.53	2.06
— Dividends	**1.28**	1.26	1.20

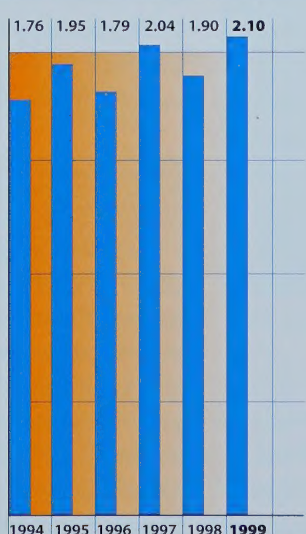


Net Income Applicable to Common Shares

$million

Earnings per Common Share (EPS)

dollars



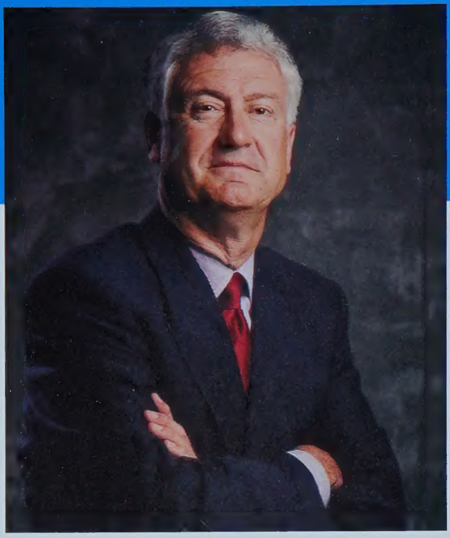
Weather Normalized EPS

dollars

Total Assets

$million

Chairman's Letter



Michael E. J. Phelps
Chairman and Chief Executive Officer

This past year marked a milestone for Westcoast Energy. During 1999, capital expenditures and investments on our major businesses and new projects totalled some $1.5 billion, the largest annual capital investment in our 50-year history. This was a considerable increase over previous years, and represents the largest of a three-year (1998 – 2000) capital investment program during which we will invest some $4 billion to position Westcoast Energy as a significant North American player in the natural gas transmission, distribution and electric power generation sectors.

Our capital investments have transformed the scope and reach of Westcoast Energy; our "footprint" has changed dramatically in the past few years. Our growth plan has positioned us to serve the rapid expansion of natural gas into new markets in Central Canada and the U.S. Pacific Northwest, as well as the Chicago area and the U.S. East Coast. We are positioning the Company to take advantage of the expansion of natural gas as the fuel of choice in rapidly growing North American markets and, in doing so, we will capture a greater share of the value of that growth for our shareholders.

In addition, we are diversifying and enhancing our business to achieve greater returns along the energy value chain. Our energy services businesses are poised to capture value in energy marketing, e-commerce opportunities, and customer services that not only enhance our bottom line, but also diversify our sources of income.

1999 Results

Our 1999 results were as follows:

- Net income applicable to common shares was $222 million in 1999, compared with $161 million in 1998.
- Earnings per common share were $1.95 in 1999, compared with $1.53 in 1998. On a weather-normalized basis, earnings per common share were $2.10 in 1999, compared with $1.90 in 1998.
- Total assets were $11.8 billion in 1999, compared with $10.8 billion in 1998.

Most of our businesses performed well. Overall results were impacted by unusual restructuring charges, and the losses at Union Energy. We are addressing these challenges and are on course with our strategic investment program. Our new investments will begin to positively impact our financial results in 2000 and beyond.

Our focus during 1999 was to ensure that our capital investments in projects at various stages of development and construction were executed on budget, on target and on time. Our success in the execution of every phase of our investments, from planning through construction to commissioning and start-up, depends on a competent and focused workforce. We have the most important element of any business – capable and dedicated employees who are making the right decisions all along the way. That is why this phase of our strategic development remained very much on track.

The Expansion of the North American Pipeline System

Our Transmission and Field Services businesses continue to produce solid results for the Company and, in 1999, contributed $154 million to net income compared with $128 million in 1998.

In British Columbia, we operate the gathering, processing and transmission facilities that move more than 1.8 billion cubic feet of natural gas per day to markets in the Lower Mainland of British Columbia and the U.S. Pacific Northwest. We are a part owner of Foothills Pipe Lines which transports 3.1 billion cubic feet of natural gas per day, or about one-third of all Canadian exports, to markets in the U.S. We own 50% of the Empire State Pipeline, which transports natural gas from Niagara Falls to New York State. We also operate a number of gathering and processing facilities for our customers across Canada.

In an increasingly deregulated, performance-based and competitive marketplace, we are working to keep this core business successful, productive and growing.

The major success story of 1999, and our largest single capital investment for the year, was the construction of the Maritimes & Northeast Pipeline. This $1.8-billion, 1,051-kilometre mainline pipeline transports Sable Offshore Energy Inc. natural gas from Goldboro, Nova Scotia, to markets in Atlantic Canada and New England. It also connects with the North American pipeline grid at Dracut, Massachusetts. Westcoast Energy has a 37.5% interest in the pipeline, and responsibility for construction and operation of the Canadian portion. Completed last autumn, the line was tested and put into service on December 1, 1999.

This pipeline is the single biggest construction project in the history of the Maritimes. It brings a whole industry to Atlantic Canada, one that allows Nova Scotia and New Brunswick to share in the benefits of the natural gas industry for the first time. It offers significant new expansion opportunities for Westcoast Energy. One Maritimes & Northeast Pipeline lateral to Point Tupper has already been built. Two more, the 124-kilometre Halifax lateral, and the 102-kilometre Saint John lateral, have received the necessary approvals from regulatory authorities and will be constructed this summer.

We are proud to be a part of this historic project, and doubly proud of Westcoast Energy's people who have worked so hard over the past five years to make this vision a reality.

The Alliance Pipeline Projects, in which we have a 23.6% interest, are some 70% complete. The 3,686-kilometre pipeline will connect producers in northeast British Columbia and northwest Alberta with markets in Chicago.

Our Transmission and Field Services businesses **continue to produce solid results** for the Company and, in 1999, **contributed $154 million** to net income compared with $128 million in 1998.

This line will utilize new high-pressure pipeline technology to move about 1.3 billion cubic feet of natural gas per day at very competitive costs of service. The pipeline and associated Aux Sable natural gas liquids plant, which are expected to cost $5.1 billion, will be brought on stream in the fourth quarter of 2000.

The Alliance Pipeline will further stimulate the growth and development of the entire northwest portion of the Western Canadian Sedimentary Basin, offering quick access and efficient transportation of natural gas to Canadian and U.S. markets. The value of our field services and pipeline infrastructure, which has been the core of the Company's success in British Columbia, will be further enhanced by the Alliance Pipeline.

Early in 2000, we finalized long-term agreements with producers in the Fort Liard area of the Northwest Territories for the transportation and processing of some 205 million cubic feet of raw natural gas per day at our Fort Nelson facility, capturing this new producing region for the Westcoast Energy system. New wells drilled in the area are some of the best in Canadian history. We expect to see increased levels of throughput as development expands.

To ensure that the natural gas reaching the Chicago terminus through the Alliance Pipeline can be delivered to markets in eastern Canada and the northeast U.S., the Company withdrew from the TriState Pipeline Project in October 1999 and joined the Vector Pipeline Project. This project, 30% owned by Westcoast Energy, will initially move about 700 million cubic feet of natural gas per day from the Chicago terminus of the Alliance Pipeline through to our Union Gas Dawn hub for markets farther east. This $855-million project has received all regulatory approvals in Canada and the U.S., is currently under construction, and will be completed for service in the fourth quarter of 2000.

We continue to be a partner in the proposed Millennium Pipeline and Millennium West Pipeline projects to take natural gas from the Dawn hub and move it farther into the northeast U.S. We are still pursuing regulatory approvals and firm transportation commitments for both projects.

These projects establish Westcoast Energy as a significant North American natural gas pipeline entity with assets stretching across the continent. In 2000, we will truly have a North American footprint.

Natural Gas Distribution

In 1999, Westcoast Energy owned and operated natural gas distribution systems in Ontario, Manitoba and British Columbia serving more than 1.4 million customers.

Union Gas represents a significant portion of the Westcoast Energy asset base. In 1999,

An Enduring Legacy

When Art Willms joined Westcoast Energy in 1971, the Company was a small regional player with assets of $500 million and 494 employees. In 1999, twenty-eight years later, Westcoast Energy has assets of approximately $12 billion and employs more than 5,600 people. Art's career has spanned those two bookends and he can claim, as his own, some measure of the success that lies between.

Much of the Company's growth arose out of acquisitions such as Union Gas and Inter-City Gas – now Centra Gas. While we were integrating new companies, new activities, new people and new business processes into our existing operations, Art's steady hand and business acumen guided day-to-day operations. In addition, he led the development of Westcoast Energy's first major underwater pipeline crossing, the Vancouver Island Pipeline.

From a single natural gas pipeline system in British Columbia, our operations now span the continent - from Vancouver Island to Goldboro, Nova Scotia on Canada's East Coast and from Fort Liard in the Northwest Territories to the Bay of Campeche in Mexico. Westcoast Energy is now one of the largest businesses in Canada and a major force in the North American energy sector.

Westcoast Energy's growth and change over the past decade echo the transformation of the energy industry. Art has played a key role in defining and managing industry issues for the Company and its industry counterparts – from incentive-based tolling to Aboriginal relations and sustainable development.

Early in his career, Art saw the need to develop working partnerships with Aboriginal groups. His commitment to Aboriginal business development is evident in the Company's partnership with the Acho Dene Koe to develop mutually beneficial opportunities in the Fort Liard region of the Northwest Territories.

The Maritimes & Northeast Pipeline is a fitting example of Art's talent and tenacity. From inception to completion, his skills were in constant demand. Art's expert testimony during regulatory hearings reflected his longstanding reputation as one of the industry's most credible and effective witnesses, and ultimately garnered a green light for the project.

Arthur H. Willms
Director
Former President and Chief Operating Officer

When Art left a career in academics to join Westcoast Energy twenty-eight years ago, he brought with him the gifts of a teacher. What he leaves behind is an enduring legacy of growth and success, and valuable lessons in courage, judgement, integrity and dedication.

The Year:

Pipeline Expansion: Maritimes & Northeast Pipeline

For the first time, natural gas is flowing from offshore fields near Sable Island to markets in Atlantic Canada and New England.

After travelling through a subsea pipeline, raw natural gas reaches onshore facilities at Goldboro, Nova Scotia, where it is processed and then transported through the 1,051-kilometre mainline Maritimes & Northeast Pipeline.

In 1999, Westcoast Energy started – and finished – the single largest construction project in the history of the Maritimes. In addition to the mainline pipeline, construction was also completed on a 59-kilometre lateral pipeline to Point Tupper, Nova Scotia. Second and third lateral pipeline projects, to Saint John, New Brunswick, and Halifax, Nova Scotia, have received all required regulatory approvals and are planned for service in 2000.

it contributed $79 million to net income, compared with a 1998 contribution of $97 million. Union Gas transferred some $500 million of service and financial assets to related companies on January 1, 1999, resulting in the decrease in net income from Union Gas.

Union Gas is an important asset not only as a distribution company but also as a result of its position at the crossroads of a number of pipelines, ensuring that the Dawn hub and the extensive storage facilities remain as key value producing assets. More natural gas flows through our Dawn hub than through all of our other facilities combined.

Our natural gas distribution business results are extremely sensitive to weather; about two-thirds of our annual revenue from our distribution business comes from mid-October to mid-April. Following five years of colder than normal weather, the past two years have delivered warmer than normal winter temperatures. To offset the effect of warm weather on our business, we focused our efforts on increasing our customer base, increasing natural gas use within that base, diversifying our revenue sources, and reducing costs. We were able to grow our Union Gas customer base by 2.7% in 1999. We have also worked to expand services at the Dawn hub and at our natural gas storage facilities.

To ensure that Union Gas remains successful in an increasingly competitive energy marketplace, the Company undertook a major streamlining program in 1999. Business processes were improved, organizational layers were reduced from nine to five, and a significant cost reduction was achieved.

Union Gas has applied to the Ontario Energy Board to implement a performance-based system of regulation, effective January 2000. We will continue our efforts to serve customers and improve performance and profitability as we proceed into an era of performance-based regulation.

We own and operate distribution businesses in British Columbia through our Centra Gas British Columbia and Pacific Northern Gas subsidiaries.

On July 30, 1999, we concluded an arrangement to sell our Centra Gas Manitoba business to Manitoba Hydro. Westcoast Energy recorded an after tax gain on the transaction of $59 million.

International Operations

The most significant international investments ever undertaken by Westcoast Energy made major progress towards completion this year. The Company is involved in two major projects in Mexico that, at year-end, represented some $395 million of invested capital.

Westcoast Energy owns 20% of the largest nitrogen production facility in the world. In September 1999, the owners of the Cantarell Nitrogen Project secured $904 million of limited recourse financing for this $1.5-billion project. The project was 95% complete at year-end, with start-up expected in the second quarter of 2000.

Work is approximately 65% complete on the $420-million Campeche Natural Gas Compression Services Project, an offshore natural gas compression and liquids recovery facility. Westcoast Energy owns 45% of the project which is scheduled for completion in mid-2000.

These two projects represent a major strategic investment for Westcoast Energy. As a significant partner in two of the largest foreign-owned energy development projects in Mexico, we are extremely well positioned to be an active participant in the development of the Mexican energy market.

Our two other international investments continue to meet targets. The Shanghai Power Project was virtually complete at year-end and will begin full operation in the second quarter of 2000. The power plant at Irian Jaya, in which we have a 43% interest, performed to expectations this year and contributed some $11 million to our financial results.

In 1999, we took steps to initiate the sale of the final pieces of our business ventures in Australia.

Power Projects

Westcoast Energy has continued to further expand as a developer, owner and operator of independent power projects. We own, either wholly or partly, five natural gas cogeneration power plants. In addition, two new projects are under construction, the 250-megawatt cogeneration power project at Elk Falls on Vancouver Island, scheduled for start-up in the third quarter of 2000, and the Bayside Power Project in Saint John, New Brunswick.

The Bayside Power Project reflects our commitment to expand our existing asset base of Maritimes & Northeast Pipeline with additional value enhancing projects. This conversion of an existing heavy oil fired power plant to a new 285-megawatt natural gas fired cogeneration unit is expected to be completed for start-up in early 2001.

We continue to evaluate and develop other power project opportunities that will add value for our shareholders.

In early 2000, we announced the sale of our 50% interest in the Liberty Power Project in Pennsylvania. We have committed to participate in the Frederickson Power Project near Seattle. This 250-megawatt combined cycle natural gas fired power generation project, which is located in closer proximity to our other business activities, is expected to begin operations in 2002.

Energy Services

Our Energy Services businesses include Engage Energy, Union Energy, Enlogix, Westcoast Capital and NGX Canada. These units are businesses that will provide us with expanded future income generating opportunities along the energy value chain.

In 1999, Engage Energy generated net income for the Company of $5 million. Engage Energy provides a valuable strategic window into the North American energy trading business, a window into the dynamic marketplace of natural gas and electricity marketing and trading. This marketing and trading capacity, prudently operated, is necessary to generate added value for our other assets and activities.

Union Energy, our retail merchandise and energy services business, encountered start-up problems in January 1999, including a major storm that created havoc in the core market area during the first weeks of operation. The net loss of the business unit, including some unusual charges and start-up costs, was $38 million. Operating losses decreased in the fourth quarter of 1999 as we worked to build more adequate systems and services to improve the business. Our commitment for 2000 is to bring this business to a break-even level. We begin with a base of some 1.1 million customers and have the potential to produce a healthy return on a relatively small equity base.

Enlogix and its associated businesses provide billing, customer information, and meter reading services to six clients serving some 2.2 million customers. Most recently, Enlogix completed the development and implementation of a customer billing system for the 325,000 utility customers of The City of Calgary. Enlogix has become one of North America's largest energy billing services providers, and Westcoast

Energy management is pursuing a number of options to accelerate growth in this business.

Westcoast Capital Corporation was formed to provide selective financial services to aid customers in the acquisition of energy-related equipment. It contributed $8 million to net income in 1999.

The Year in Broad Context

We are well into the third year of a major investment program that is positioning us for growth and future results. The projects in which we are investing will begin to contribute to income this year.

The North American and Canadian natural gas transmission and distribution sector has been adversely impacted by a number of events that have made the achievement of satisfactory results in 1999 a struggle for the industry and for Westcoast Energy.

Abnormally warm weather over the past two years has not benefited the natural gas distribution businesses. We have a considerable investment in pipeline and distribution infrastructure that does not operate at full capacity when weather is warmer than normal. If average winter temperatures do not materialize, the impact is felt throughout our business and impacts an entire year's results. We continue to mitigate the effect of warmer weather by cutting costs, seeking new sources of revenue and diversifying our businesses.

In 1999, a concern developed about the emerging difficulty of attracting capital to the pipeline and utility sector at an appropriate cost in order to fund growth.

Regulators at the national and provincial level have, over the past few years, reduced the approved rates of return for the regulated utility parts of our Company and our industry. The rates of return prescribed by regulators in Canada are significantly lower than those in the U.S., and lower than the market suggests is necessary to attract future investment capital back to the pipeline and utility sector.

Westcoast Energy management has always supported the deregulation of the industry, and the move to more performance-based models of regulation. We are working with regulators to implement performance-based regulation as one way to improve our return on equity.

A second reality of today's market is that other sectors are attracting more investor interest. Pipeline and utility stocks are not attracting the same attention from investors that they have in the past. The result is that our capacity to raise funds from new equity investors has declined; low share values are not conducive to growth.

We believe that this is a transition phase. We believe regulators will recognize our need to efficiently attract new capital, particularly if environmental and economic development policy goals are to be met.

In addition, we anticipate that investors will renew their interest in the significant value-creating steps made by the Company to position itself to take advantage of this exciting era for the natural gas, electric power and energy services sectors.

The Year Ahead

Over the past decade, society and business have become enthralled and overwhelmed with a technological revolution that is changing our daily lives. We have been mindful of the benefits that this technological revolution brings to every sector of business and society, and we are enthusiastically working to take full advan-

Corporate Responsibility

We strive to ensure that our operations – and our actions – protect and enhance the economy, the environment and the communities in which we operate. These efforts are focused on creating sustainable development, development "that meets the needs of the present without compromising the ability of future generations to meet their own needs."

Our enterprise-wide Environment, Health, Safety and Sustainable Development Policy guides the work of our employees, and informs customers and stakeholders of our focus. Our annual Sustainable Development Review shares a record of progress on environment, health, safety and community initiatives.

We believe that natural gas is part of the solution to climate change. As the least carbon intensive fossil fuel, natural gas will play an important role in meeting today's growing energy needs, while bridging the transition to tomorrow's new, renewable energy sources. As part of a global effort, we continue to identify and champion practical and realistic solutions to greenhouse gas emissions reductions, including:

- **construction of the Bayside Power Project, the conversion of a heavy fuel oil generating plant into a combined cycle plant that will use a single fuel – natural gas – to produce two energy sources, electric power and steam; and**
- **construction of the Campeche Natural Gas Compression Services Project, an offshore facility that will recover natural gas, previously burned-off or flared, for delivery into Mexico's natural gas pipeline network.**

Our community involvement is focused on the regions in which we operate. Our intent is to build mutually beneficial relationships with landowners and Aboriginal and remote communities, and to encourage our employees to actively participate in the communities where they work and live.

In 1999 we worked with the Indian Advisory Taxation Board on the development of equitable property taxation systems for First Nations on whose reserves we have facilities. In the Northwest Territories, we developed an innovative joint venture agreement with an Aboriginal community at the centre of new industry activity in the Fort Liard area. These efforts reflect a commitment to structure our activities to allow local businesses to share in the economic benefits of our operations.

In 1999 we lent our financial support to numerous not-for-profit organizations. In total, the Company contributed $1.5 million to registered charitable organizations, including:

- **the Westcoast Energy Children's Centre, a unique partnership between the Company, the North Vancouver School Board and Family Services of the North Shore. The Centre provides programs in support of research linking early childhood development to adult success; and**
- **the "Your Health, Your Future" campaign of the Foundation of Chatham-Kent Health Alliance, the recipient of one of the largest donations in the history of the Company's Union Gas subsidiary. In recognition of this commitment, the new ambulatory care area for patients requiring elective, non-emergency medical treatment will be named the Union Gas Ambulatory Care Centre.**

These programs are not adjunct to our operations, they are integral to our day-to-day activities. We believe that these are business practices of merit, and represent added value for our shareholders.

The Year:

Pipeline Expansion: Alliance Pipeline

The Alliance Pipeline will create an efficient, cost-effective natural gas transportation route from northeast British Columbia and northwest Alberta to the U.S. Midwest.

Each day, more than one billion cubic feet of natural gas will flow from Western Canada to the Chicago, Illinois area market centre. From Chicago, natural gas will move to growing North American markets where it will meet increasing demand, particularly for the generation of electric power.

During 1999, construction crews in Canada and the United States installed more than 2,150 kilometres of the entire 3,686-kilometre pipeline project. The remaining mainline pipeline and lateral pipeline construction will be completed in 2000, with service expected to begin in late 2000.

Maritimes & Northeast Pipeline will contribute **a full year's worth of income** to our bottom line in 2000. The Saint John and Halifax laterals will be built this summer. Maritimes & Northeast Pipeline has called for an open season on additional volumes and **was pleased** with the expressions of interest. We are becoming **a major business force** in Atlantic Canada.

tage of technological enhancements to improve the value of our assets and our businesses.

Many of our energy services businesses are capitalizing on this new technology in billing systems, meter reading, web-based information utilization, commodity trading, natural gas and electricity marketing, and customer service systems.

Our core businesses are adopting the latest in information technology to serve our customers. We all benefit from these leaps of technology and we will capture the value they represent to our business.

We are confident that there will be dramatic increases in demand for natural gas throughout North America. Our growth strategy is to capitalize on this increase in demand for natural gas, and to become a significant North American player by providing superior energy services value to our customers.

Westcoast Energy is the only company serving both of the most prospective basins for new sources of natural gas in North America; East Coast Offshore and the lower portion of the Northwest Territories. We are also well positioned to capitalize on any future development in the Mackenzie Delta, Beaufort Sea and Alaska North Slope regions.

Maritimes & Northeast Pipeline will contribute a full year's worth of income to our bottom line in 2000. The Saint John and Halifax laterals will be built this summer. Maritimes & Northeast Pipeline has called for an open season on additional volumes and was pleased with the expressions of interest. We are becoming a major business force in Atlantic Canada.

The Alliance Pipeline will come on stream in late 2000, providing a vital new competitive link between producers and customers. The Aux Sable natural gas liquids facility will start operations in conjunction with the Alliance Pipeline. The Vector Pipeline will be operational in the fourth quarter and we continue to develop the Millennium Pipeline and Millennium West Pipeline projects.

We have captured the processing and transportation of much of the new natural gas production from the Fort Liard region of the Northwest Territories, increasing the utilization of our existing system.

On the distribution side, Union Gas is preparing to operate under a new performance-based regulatory system that will allow us to evolve from a restrictive, cost-recovery model to a competitive, commodity-based business without a regulated cap on our returns. We believe that performance-based regulation will allow Union Gas to be more efficient and effective for customers, and provide more value to our shareholders.

Internationally, both of our Mexican projects, Campeche and Cantarell, are expected to begin service in the second quarter of 2000. The Shanghai Power Project will begin commercial operation in the second quarter of 2000.

Both the Island Cogeneration and Bayside Power projects will complete their most capital intensive construction phases in 2000, and will begin contributing to net income in 2001.

We will continue to manage our newer services businesses through their start-up phases to increasing levels of profitability. These particular initiatives have had a near-term cost but, as services businesses, they represent important income generating opportunities along the value chain and outside of the regulated environment. They have the potential to add significant value in an increasingly competitive and deregulated energy market, and to provide leverage for our regulated businesses.

Westcoast Energy has funded its historic three-year capital expenditure program utilizing a mix of internally generated funds, redeployment of capital, new equity, and debt. We will prudently manage the final year of this investment program.

In 2000, we are committed to living within our means. We will fund our $1.3-billion capital investment program by raising debt and using internally generated funds. That may mean that we will alter our existing mix of assets by selling certain assets and using the proceeds to fund other investments where we see a greater opportunity for growth and returns. We will redeploy our capital resources whenever we see an opportunity to maximize value for our shareholders.

We believe that we have a solid strategy for moving confidently into the future. We also believe that the investments we are making today will provide greater returns for our shareholders well into the future.

The future of natural gas as the fuel of choice for North America is becoming more obvious each day. Demand is strong, prices remain strong even in the face of warm weather, and demand for natural gas is forecast to grow. Natural gas is quickly becoming the favoured fuel of choice for energy needs because it is a cost-efficient and environmentally superior alternative to other fossil fuels and nuclear energy. The growing concern over Canada's, and indeed North America's, commitment to meeting the Kyoto-round targets augurs well for the future of natural gas. Our sizeable investment program in 1998, 1999 and 2000 positions us to take advantage of this strong market demand. We believe that Westcoast Energy, and the industry of which we are a part, will grow and prosper. We will secure a bigger share of this future prosperity.

Finally, on behalf of the Board of Directors, I would like to acknowledge the contribution and service of James S. Palmer. Jim was elected to the Board in 1990 and retired in October 1999.

Michael E.J. Phelps
Chairman and Chief Executive Officer
March 1, 2000

Financial Review

In 1999, Westcoast Energy completed 85% of the construction on the Island Cogeneration Project. This 250 megawatt power plant, located at a pulp and paper mill near Campbell River, British Columbia, will use natural gas to generate steam for mill operations and electrical power which will be sold under a 20-year electricity purchase agreement.

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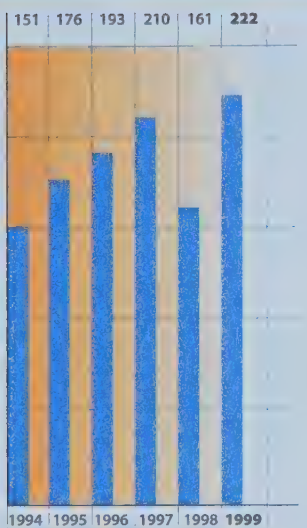
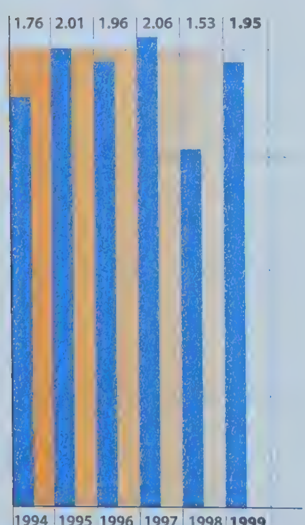
Management's Discussion & Analysis



Net Income Applicable to Common Shares

$million



Earnings per Common Share (EPS)

dollars

This discussion and analysis of the Company should be read in conjunction with the consolidated financial statements and accompanying notes. The results reported herein have been prepared in accordance with accounting principles generally accepted in Canada and are presented in Canadian dollars. The effects on net income arising from the variances between accounting principles generally accepted in Canada and the United States are described in note 20 to the consolidated financial statements.

The consolidated financial statements include the accounts of the Company, its subsidiaries, and its proportionate share of joint venture investments.

The Company realized higher earnings in 1999 compared with 1998 as a result of colder weather experienced in 1999 compared with the unusually warm temperatures in most of the Company's gas distribution franchise areas in 1998. While colder than 1998, weather was again warmer than normal, which adversely impacted the Company's results. Weather normalized earnings per common share were $2.10 and $1.90 for 1999 and 1998, respectively.

Unusual items in 1999 increased earnings by 18 cents per common share. The major contribution was the gain on the sale of Centra Gas Manitoba ($59 million after tax or 52 cents per common share). The gain on sale was partially offset by certain unusual charges within the Company's retail energy services business, restructuring costs primarily resulting from business transformation initiatives at Union Gas Limited (Union Gas), and the write-off of costs related to development projects, totalling 34 cents per common share. In total, and on a net basis, weather and the unusual items noted above increased earnings by 3 cents per common share in 1999.

Fiscal 1998 results include unusual charges which reduced earnings by 11 cents per common share. These reflect Centra Gas Manitoba's disallowance of natural gas costs by the Manitoba Public Utilities Board (MPUB) net of recoveries, Engage Energy's loss arising from customer defaults, and the write-off of the Company's investment in a small unregulated natural gas processing plant. These were partially offset by the gain on the sale of Centra Gas Alberta and the gain on the sale of our interest in the Australian Eastern Gas Pipeline Project.

After adjusting for weather and unusual items, earnings per common share for the years ended December 31, 1999, 1998 and 1997 were $1.92, $2.01 and $2.04, respectively.

CONSOLIDATED OPERATIONS

Years ended December 31 ($million)	1999	1998	1997
Net income applicable to common shares	222	161	210
Weather	17	39	(2)
Weather normalized earnings	239	200	208
Divestitures			
Sale of Centra Gas Manitoba	(59)	—	—
Sale of Fort Nelson powerline	(3)	—	—
Sale of Centra Gas Alberta	—	(14)	—
Sale of Australian Pipeline	—	(8)	—
Unusual items			
Union Energy charges	18	—	—
Restructuring charges	10	—	—
TriState Pipeline Project	3	—	—
Centra Gas Manitoba disallowance	—	12	—
Engage Energy credit loss	—	14	—
Buckinghorse Gas Plant write-off	—	7	—
Other	10	—	—
Weather and unusual items normalized earnings	218	211	208
($/share)			
Earnings per common share	$1.95	$1.53	$2.06
Weather	0.15	0.37	(0.02)
Weather normalized earnings per common share	2.10	1.90	2.04
Unusual items			
Sale of Centra Gas Manitoba	(0.52)	—	—
Other	0.34	0.11	—
Weather and unusual items normalized earnings per common share	$1.92	$2.01	$2.04

The 1999 results reflect higher contributions from new pipeline projects and strong contributions from the British Columbia Pipeline and Field Services divisions which benefited from higher gas prices. There was also a marked improvement in the results of Engage Energy due to structured natural gas and power transactions, improved management of risk capital and a continued emphasis on cost containment. Earnings were, however, negatively impacted by losses in the Company's retail energy services business and lower allowed rates of return on common equity for the Company's regulated gas distribution businesses and Foothills Pipe Lines.

With respect to the previous year's results, higher earnings were realized in 1998 compared with 1997 from a number of the Company's operations, including the British Columbia Pipeline and Field Services divisions, new pipeline projects and international operations. We also saw continued growth in the number of natural gas distribution customers and rate bases, higher service and rental revenues and the higher utilization of previous years' unrecorded tax losses.

These factors were more than offset by unusually warm weather experienced in the Company's gas distribution franchise areas in 1998 compared with 1997. The earnings contribution applicable to the Gas Distribution businesses is subject to weather variances which reduced earnings per common share in 1998 by 39 cents when compared with 1997.

1998 earnings were also reduced by start-up costs related to the Company's retail energy services business, lower allowed rates of return on common equity applicable to the majority of the Company's regulated businesses, operating losses incurred by the energy marketing business, costs related to the Year 2000 program, higher interest expenses and higher financing costs as a result of having significant capital invested in projects under development that are not yet earning income.

Operating revenues and cost of sales have decreased in 1999 compared with 1998 primarily due to lower trading activity by Engage Energy, offset partially by colder weather in 1999 compared with 1998 and the contribution generated in 1999 from 13 new heating, ventilation and air conditioning (HVAC) operations acquired by the Company's retail energy services business. Prior year cost of sales include unusual charges by Centra Gas Manitoba for certain natural gas costs related to price management activities which were disallowed by the MPUB, and also include Engage Energy losses arising from customer defaults.

The increase in operating revenues and cost of sales in 1998 over 1997 primarily reflects higher natural gas and electric power volumes traded by Engage Energy, revenues and costs generated from 15 new HVAC operations acquired by the Company's retail energy services business in 1998 and higher revenues from the Company's Indonesian power joint venture, resulting from the acquisition of an additional interest in the power facilities in late 1997, together with an expansion of the facilities. These increases were partially offset by lower revenues from the Gas Distribution businesses due to warmer weather in 1998 compared with 1997. Engage Energy's loss arising from customer defaults and the MPUB's disallowance of certain natural gas costs incurred by Centra Gas Manitoba related to price management activities also accounted for the increase in cost of sales in 1998.

The effective consolidated income tax rate for 1999 was 14.2%, compared with 19.0% in 1998 and 33.4% in 1997. The lower effective tax rate is attributable to a drawdown of deferred taxes by Union Gas as approved by the Ontario Energy Board (OEB) and the utilization of previous years' unrecorded tax losses, partially offset by the deferred taxes recorded on the gain from the sale of Centra Gas Manitoba. Details of the consolidated income tax provisions are provided in note 7 to the consolidated financial statements and a discussion of other taxes is noted below under Taxation.

RESULTS BY BUSINESS SEGMENT

The operations of the Company have been grouped according to the following business segments:

- Transmission & Field Services – natural gas gathering, processing and transmission;
- Gas Distribution – natural gas distribution and storage and transmission;
- Power Generation – electrical and thermal energy generated from natural gas;
- International – international operations;
- Services – energy marketing, retail energy services, information technology and financial services;
- Other – other activities, including corporate expenses, business development expenditures, corporate financing expenses and utilization of previous years' unrecorded tax losses.

The contribution to net earnings by these business segments, after allocation of acquisition costs, was:

Years ended December 31 ($million)	1999	1998	1997
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES			
Transmission & Field Services	154	128	114
Gas Distribution	154	122	161
Power Generation	11	6	11
International	15	16	5
Services	(32)	(46)	(15)
Other	(80)	(65)	(66)
	222	161	210

Additional segmented information is provided in note 19 to the consolidated financial statements.

TRANSMISSION & FIELD SERVICES

The operating businesses included in this segment consist of the British Columbia Pipeline and Field Services Divisions, the non-National Energy Board (NEB) regulated Field Services Division, Foothills Pipe Lines Ltd. (Foothills), Empire State Pipeline, the Maritimes & Northeast Pipeline, the Alliance Pipeline, the Vector Pipeline Project, St. Clair Pipelines (1996) Ltd. (St. Clair), NrG Information Services Inc. (NrG) and a sulphur products facility.

The contribution to net earnings for Transmission & Field Services was:

Years ended December 31 ($million)	1999	1998	1997
NET INCOME (LOSS) CONTRIBUTION			
British Columbia Pipeline and Field Services Divisions	93	104	94
Non-NEB regulated Field Services Division	2	(7)	1
Foothills	9	9	9
Empire State Pipeline	8	10	8
Maritimes & Northeast Pipeline	18	9	4
Alliance Pipeline	20	4	—
Vector Pipeline Project	1	—	—
Other	3	(1)	(2)
	154	128	114

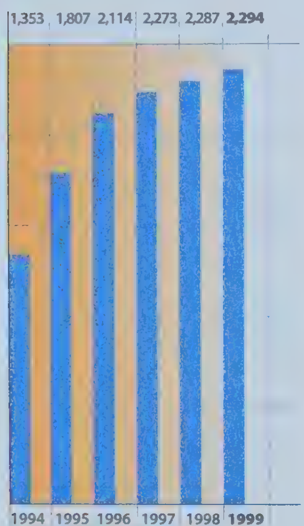
Fiscal 1999 net earnings from the Transmission & Field Services business of $154 million represent increases of $26 million and $40 million, respectively, compared with 1998 and 1997.

Weather Normalized EPS

dollars

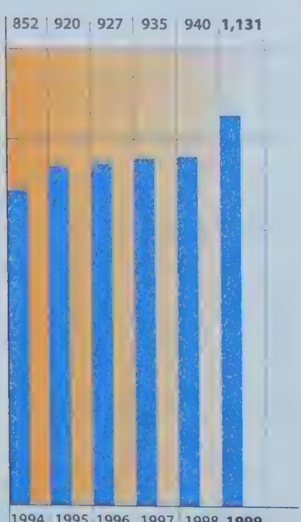
B.C. Pipeline Division Volumes

billion cubic feet



B.C. Pipeline and Field Services Divisions Average Rate Bases

$million



Foothills Pipe Lines Volumes

billion cubic feet

The increase in the contribution to net earnings for Transmission & Field Services in 1999 over 1998 and 1997 is primarily due to two new pipeline projects, Maritimes & Northeast Pipeline and Alliance Pipeline. Increased capital spending and a higher level of investment in these projects contributed to an increase in the amount of allowance for funds used during construction (AFUDC) recorded. Fiscal 1998 net earnings, when compared with 1997, reflected higher contributions from the British Columbia Pipeline and Field Services Divisions and Empire State Pipeline in addition to the AFUDC recorded on our new pipeline projects. The 1998 results were impacted by the $7 million after-tax write-off of an investment in a small, unregulated natural gas processing plant.

British Columbia Pipeline and Field Services Divisions

The Company's integrated natural gas gathering, processing and transmission system in British Columbia, Alberta, and the Yukon and Northwest Territories consists of approximately 5,600 kilometres of natural gas gathering and transmission pipelines and five gas processing plants which include three sulphur recovery plants. These facilities are regulated by the NEB.

The majority of the Transmission & Field Services segment's net earnings continue to be generated from the British Columbia Pipeline and Field Services divisions. These divisions operate under the multi-year incentive toll settlement, which was approved by the NEB in 1997. Under the multi-year incentive toll settlement, effective January 1, 1997, gathering and processing tolls are partially indexed to natural gas prices in representative market areas served by natural gas transported through the system. As a result of increasing gas prices, demand toll revenues in 1999 increased $13 million when compared with 1998, and increased $11 million in 1998 over 1997. In 1999, this increase was more than offset by lower contract demand revenues in the Field Services Division, and higher operating and maintenance costs, mainly as a result of a scheduled outage at the McMahon Plant. The return on common equity realized by these divisions was 11.51% in 1999, compared with 12.95% in 1998 and 11.62% in 1997.

Natural gas is delivered to markets in British Columbia, other parts of Canada and the western United States. Total throughput on the transmission mainline in 1999 was 670 billion cubic feet (Bcf), compared with the record levels achieved in 1998 and 1997 of 688 Bcf. The lower volumes in 1999 were largely due to reduced demand as a result of warmer weather.

Multi-Year Incentive Toll Settlement

The British Columbia Pipeline Division operates under the multi-year incentive toll settlement which is effective from 1997 to 2001. The settlement provided transmission customers a one-time option of contracting for fixed tolls for a contract term of 5 years, or tolls that are adjusted annually in accordance with a prescribed incentive methodology. Fixed tolls for 5-year service were based on a 10.67% return on common equity. Approximately 70% of the customers contracting for firm transmission service elected the 5-year fixed toll option.

The multi-year incentive toll settlement provided gathering and processing shippers the one-time option of contracting for fixed base tolls for 1, 3, or 5-year service. The base tolls reflect a 500 basis point reduction from the NEB prescribed rate of return on common equity for 1997 of 10.67% and are subject to a monthly surcharge based on an index of monthly gas prices. The gas price sensitive monthly surcharge allows the Company the opportunity to earn additional revenue when gas prices rise. Under the framework for light-handed regulation described below, the Company and its customers are to negotiate replacement contracts as the business need arises or as the 1, 3, or 5-year tolls expire.

The multi-year incentive toll settlement was subject to agreement by the Company and its customers and other stakeholders on the principles of light-handed regulation applicable to the Company's gathering and processing services. In January 1998, the Company and its stakeholders agreed to a framework for light-handed regulation. This framework became effective immediately upon its approval by the NEB in June 1998. The framework defines the principles under which the Company negotiates individual service contracts with shippers for gathering and processing services, including the tolls applicable to such services. Consistent with these principles, the Company is responsible for the utilization of its gathering and processing assets and, accordingly, tolls for service are no longer based on the cost of service method of regulation.

Contractual Developments

Approximately 10% of transportation service on the Company's southern mainline facilities was not renewed effective November 1, 2000. Effective November 1, 1999, approximately 15% of the regulated gathering and processing volumes were decontracted. Approximately 3% of the gathering and processing volumes have been recontracted by the end of 1999. A portion of the decontracted volumes is expected to flow on an interruptible basis.

The Pipeline and Field Services divisions and members of the West Liard Valley Producers' Group (LVPG) have signed long-term agreements for the transportation and processing of LVPG's West Liard, Northwest Territories area natural gas at the Company's Fort Nelson, British Columbia facility. The Company estimates the new area to contain 2.2 trillion cubic feet of natural gas reserves. The agreement provides for an initial raw gas rate of 205 million cubic feet per day (MMcf/d), and includes provisions for future capacity increases as area development proceeds. Production is expected to commence in June 2000.

Additional service continues to be provided on an interruptible basis. The domestic and export markets served by the British Columbia pipeline system remain strong, as does the supply of northeastern British Columbia gas. Accordingly, the Company expects to have continued high level of system utilization.

Non-NEB Regulated Field Services

Westcoast Gas Services Inc. owns interests in four provincially regulated natural gas processing plants and one liquids pipeline system.

In 1998, the Company wrote off its investment in the Buckinghorse natural gas processing plant due to low drilling activity and production in the area served by the plant, resulting in a reduction to net earnings of $7 million, or 7 cents per common share.

Foothills

The Company has a 50% interest in Foothills, which, through subsidiaries, transports Canadian natural gas to markets in the United States through portions of the Canadian segment of the Alaska Natural Gas Transportation System which were prebuilt (Phase I). The earnings in 1999 were positively impacted by a higher rate base resulting from the Eastern Leg expansion project, offset by a lower NEB determined return on equity.

The NEB approved return on equity for 2000 is 9.90%, compared with 9.58% in 1999. The common equity component of rate base remains at 30%.

Empire State Pipeline

The Company has a 50% interest in the Empire State Pipeline, located in upper New York State, which indirectly connects the natural gas transportation and storage facilities of Union Gas in Ontario with markets in upper New York State. Higher earnings in 1998 can be attributed to a stronger United States dollar and the payment received on the cancellation of a transportation contract by one shipper. The capacity related to this contract has been substantially replaced with new firm or interruptible contracts.

In January 1997, the New York Public Service Commission approved new tolls effective November 1, 1996, which included a 12.5% rate of return on common equity, and maintained the common equity component of rate base at 40%. The tolls are based on a 7-year average rate base of $214 million. Empire State Pipeline achieved this rate of return and common equity component for 1998 and 1999, and is expected to continue to do so in 2000.

Pipeline Projects

Maritimes & Northeast Pipeline

The Company has a 37.5% interest in the Maritimes & Northeast Pipeline (M&NP), which will transport in excess of 500 MMcf/d of natural gas sourced from offshore fields near Sable Island to markets in Nova Scotia, New Brunswick and the northeast United States. The 1,051-kilometre main pipeline and associated lateral pipelines are expected to cost approximately $1.8 billion.

M&NP generated net earnings of $18 million in 1999, an increase of $9 million compared with 1998, and is a major contributor to the higher net earnings realized by the Transmission & Field Services segment in 1999. Net income is primarily due to the recording of AFUDC.

M&NP went into service on December 1, 1999 and received the first shipment of natural gas from Sable Offshore Energy Inc. on December 31, 1999. The pipeline will have an initial contracted flow of 445,000 million British Thermal Units (MMBTU) per day. This level of flow will be increased in the fall of 2000, once the Halifax and Saint John lateral pipeline projects are completed. Both lateral projects have received NEB approval.

Currently, M&NP is operating under NEB-approved interim tolls. The interim tolls are based on a return on equity of 13%. M&NP filed for final tolls for the December 1, 1999 to September 30, 2000 period on February 28, 2000. A decision from the NEB on final tolls for this period is expected by the third quarter of 2000.

In December 1999, M&NP completed testing of the Point Tupper lateral pipeline, which is expected to be brought into service once regulatory approvals are granted.

Alliance Pipeline

The Alliance Pipeline will deliver about 1.3 Bcf per day of natural gas from Western Canada to the Chicago area. Direct capital costs (excluding allowance for funds used during construction) for the 3,686-kilometre pipeline are currently estimated at $4.5 billion and the Aux Sable Chicago area liquids recovery facilities associated with the pipeline are expected to cost an additional $540 million.

The recording of AFUDC resulted in equity earnings from the investment in the Alliance Pipeline projects of $20 million in 1999, an increase of $16 million over 1998. This investment is a major contributor to the higher earnings experienced by the Transmission & Field Services segment.

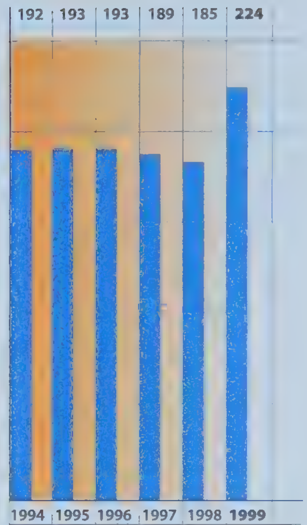
The Company entered the projects in late 1997 with a 10.5% interest, and has purchased additional interests in the projects from existing partners. In January 1998, the Company acquired a 4% interest and in December 1998, the Company acquired an additional 9.1% ownership interest in the Alliance Pipeline, increasing the Company's interest in the projects to 23.6%.

In addition to its ownership interest in the Alliance Pipeline, the Company took assignment of a long term capacity commitment for 66 MMcf of natural gas per day. Union Gas also subscribed for 80 MMcf/d of long-term capacity on the Alliance Pipeline.

The Alliance Pipeline is 70% complete and the remaining pipeline will be installed during 2000. Construction also continues on the Aux Sable natural gas liquids facility in Chicago, Illinois. The pipeline and the natural gas liquids recovery facility are expected to begin operation in the fourth quarter of 2000.

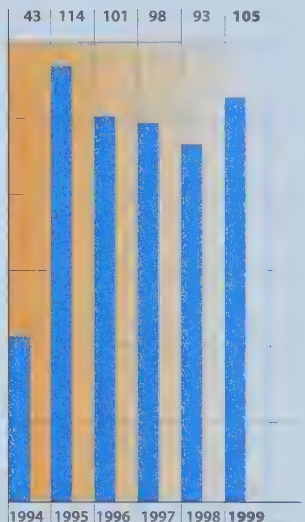
Vector Pipeline Project

The Company purchased a 30% equity interest in the Vector Pipeline Project (Vector) during 1999. Vector involves the construction of a natural gas transmission pipeline extending approximately 553 kilometres from a point near Chicago to the Union Gas hub at Dawn,



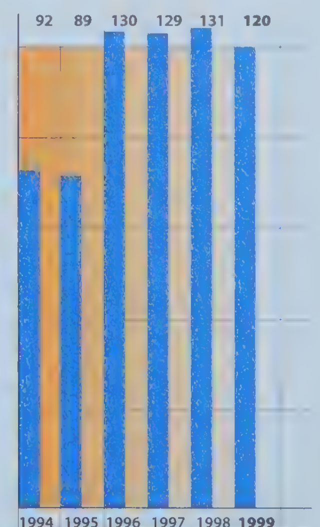
Foothills Pipe Lines Average Rate Base

proportionate share / $million



Empire State Pipeline Volumes

billion cubic feet



Empire State Pipeline Average Rate Base

proportionate share / $million

Ontario. The Vector pipeline will connect with the Alliance Pipeline and other natural gas transmission systems near Chicago, and will also connect with the proposed Millennium West Pipeline Project at Dawn. The Vector pipeline will have an initial capacity of approximately 700 MMcf of natural gas per day. The pipeline will service markets in Michigan and Ontario and, through connecting pipelines, other markets in Eastern Canada and the northeastern regions of the United States.

The recording of AFUDC by Vector contributed approximately $1 million to net income applicable to common shares for the year ended December 31, 1999.

The Vector pipeline has received the necessary regulatory approvals from the NEB for the portion of the pipeline to be constructed in Canada, and from the United States Federal Energy Regulatory Commission for the portion of the pipeline to be constructed in the United States. Construction commenced in January 2000 and the pipeline is expected to begin operation in the fourth quarter of 2000. The total capital costs of the project are estimated to be approximately $855 million. In addition to the acquisition of a 30% interest in Vector, the Company took an assignment of a long term capacity commitment for 160 MMcf of natural gas per day on Vector. Union Gas has also subscribed for 80 MMcf/d of long-term capacity on Vector.

Other

The Transmission & Field Services segment derived a small portion of its net earnings in 1999 from three investments. These include:

- a sulphur products facility located in Prince George, British Columbia (in which the Company's participation in earnings increased from 32% to 50% in February 1999);
- pipeline facilities of St. Clair which connect Union Gas' natural gas transportation and storage facilities to pipeline and storage facilities in the United States; and
- a one-third interest in NrG which provides the electronic commerce capability between pipelines and their shippers.

Transmission & Field Services Outlook

The outlook for the Transmission & Field Services businesses remains strong. Natural gas continues to evolve as the fuel of choice for energy needs as it is a cost efficient and environmentally superior alternative to other fossil fuels and nuclear energy.

Demand forecasts for natural gas in North America indicate continued growth in demand, both in Canada and the United States. The bullish gas environment will increase demand for gas processing and pipeline capacity in the foreseeable future. The Company's processing and mainline infrastructure in northeastern British Columbia and Atlantic Canada is well positioned to provide these services for gas supply from the traditional Western Canadian Sedimentary Basin, Southern Northwest Territories and East Coast Offshore. Growth in demand for natural gas is forecast to be generated by continued economic expansion in existing markets, access to new markets which have not been served by natural gas in the past and from additional demand for natural gas to fuel the generation of electrical power.

Natural gas reserves in North America, including the McKenzie Delta and Alaska, are felt to be sufficient to meet the forecast demand growth over the longer term. Improvements in exploration and production technology have reduced the risks associated with the development of additional reserves.

Capital expenditures

To support the growing market demand for natural gas, additional transportation infrastructure is needed to facilitate the delivery of natural gas. As a result, the Company proceeded with its largest ever capital expenditure program in 1999, the peak year of a three-year capital expansion program, in order to construct additional infrastructure that is needed to support this growing demand for natural gas. The Transmission and Field Services segment expects to spend $632 million on capital expenditures in 2000, a decrease of $150 million or 19% from 1999. These expenditures are primarily for M&NP, Alliance Pipeline and Vector.

Transmission & Field Services Business Risks

Competition

The regulatory environment in which the majority of the Company's assets operate continues to evolve from the traditional cost recovery model to a less regulated, competitive, commodity-based business. The current favourable natural gas climate and customer demands for tailored services has led to increased competition from midstream service companies and producers. This competition for more efficient, flexible services resulted in the Company renegotiating its business processes and tolls on its British Columbia mainline and its British Columbia gathering and processing business. In return for lower base tolls and accepting a higher degree of throughput utilization risk, the Company is now in a position to compete with others, in a timely manner, for gathering and processing services under flexible terms and conditions.

Regulatory

Regulatory changes have occurred and are occurring in the gathering and processing and transmission businesses. Changes to the regulatory environment are increasing the risk of the business as a portion of revenue is sensitive to gas prices and responsibility is placed on the Company to generate sufficient revenues and costs to ensure appropriate returns on investments. As a result of the current regulatory environment, the Company is developing opportunities to increase the potential returns from its regulated businesses.

The traditional rates of return prescribed by the regulators for established Canadian pipeline companies are significantly lower than those in the United States, and than the market suggests is necessary to attract future investment capital back to the pipeline and utility sector.

The multi-year incentive toll settlement will expire on December 31, 2001 with respect to the Company's British Columbia Pipeline Division Transmission Tolls and with respect to the tolls on the Company's NEB regulated gathering and processing facilities. Under the framework for light-handed regulation, the Company and its customers are to negotiate agreements to replace the tolls for gathering and processing services. In addition, it is anticipated that the Company will begin discussions concerning its transmission tolls for the period following December 31, 2001 with its customers and other stakeholders later this year.

Financial

A large portion of the financial returns on the British Columbia gathering and processing business are linked to natural gas prices. Revenue can be impacted as gas prices fluctuate in a range of US$1.35 and US$2.00 per MMBTU of natural gas.

To maintain throughput in the Field Services Division, the Company has been forced to negotiate deals that yield returns below what would be used in establishing tolls in a regulated environment. There is a risk that this type of price competition will continue in the future yielding lower returns on assets.

Physical Capacity

The Company holds long term transportation capacity on the Alliance and Vector pipelines. The Company is actively seeking to assign this capacity to third parties in order to mitigate its exposure to price volatility. In addition, the Company uses financial instruments to hedge the price exposure.

The Fort Nelson and Grizzly Valley areas in British Columbia continue to have strong demand for gathering and processing services. The Fort St. John area continues to be very competitive with all midstream assets in the area continuing to face lower utilization rates. Growing interest in developing additional supply in the region combined with management initiatives to attract additional volumes would help minimize ongoing capacity risk.

Exploration and Production Risk

The Company's financial success in the transmission of gas through pipelines is predicated on exploration and production companies' successful drilling for natural gas. This, in turn, is closely linked to the level of commodity prices driven by market demand and technical risks associated with the natural gas exploration business.

GAS DISTRIBUTION

The operating businesses included in this segment primarily consist of the natural gas distribution and transmission and storage businesses of Union Gas, Centra Gas British Columbia Inc. (Centra Gas BC), Pacific Northern Gas Ltd. (PNG) and a business related to natural gas-fuelled vehicles.

The contribution to net earnings for Gas Distribution was:

Years ended December 31 ($million)	1999	1998	1997
NET INCOME (LOSS) CONTRIBUTION			
Union Gas (1)	79	97	128
Centra Gas BC	12	12	12
PNG	3	3	3
Centra Gas Manitoba	65 (2)	(4)	14
Centra Gas Alberta	—	16 (3)	4
Other	(5)	(2)	—
	154	122	161

(1) includes Centra Gas Ontario Inc. which was amalgamated with Union Gas effective January 1, 1998

(2) includes an after-tax gain of $59 million on the sale of Centra Gas Manitoba

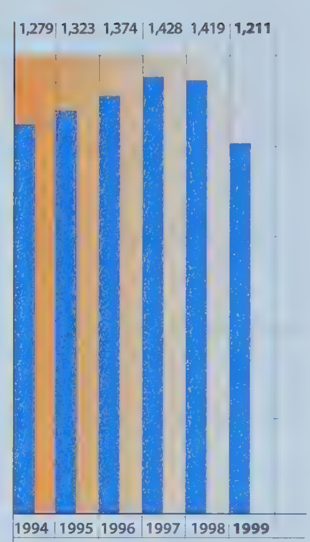
(3) includes an after-tax gain of $14 million on the sale of Centra Gas Alberta

The Gas Distribution businesses contributed net earnings of $154 million in 1999, compared with $122 million and $161 million in 1998 and 1997, respectively. Annual results include divestitures in 1999 and 1998, and a Centra Gas Manitoba regulatory decision in 1998.

Net earnings for 1999 reflect the sale of Centra Gas Manitoba, which resulted in an after-tax gain of $59 million, a loss provision in anticipation of the sale of a small investment, and restructuring costs resulting from business transformation initiatives at Union Gas. Fiscal 1998 results were impacted by the $14 million after-tax gain on the sale of Centra Gas Alberta. An unusual charge of $12 million was recorded in 1998 to reflect the MPUB disallowance of certain natural gas costs incurred by Centra Gas Manitoba related to price management activities.

The Gas Distribution businesses are sensitive to variations from normal weather conditions. Colder than normal weather conditions produce higher revenues and earnings, with the opposite result occurring in warmer than normal weather conditions. Although the weather in 1999 was warmer than normal, fiscal 1999 experienced higher earnings when compared with 1998 partially as a result of colder weather. The decrease in the contribution to net earnings for Gas Distribution in 1998 compared with 1997 primarily reflects the unusually warm temperatures in most of the Company's gas distribution franchise areas. In 1999 and 1998, earnings were reduced by $17 million (15 cents per common share) and $39 million (37 cents per common share), respectively, by warmer than normal weather, whereas in 1997 earnings benefited by $2 million (2 cents per common share) due to colder than normal weather.

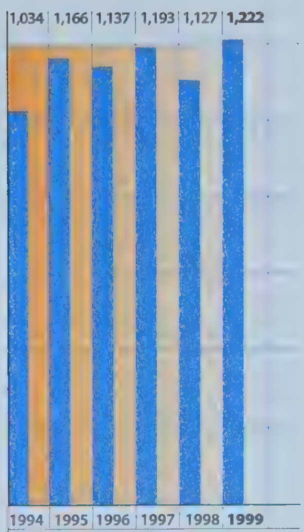
Excluding the impact of weather, and adjusting for the unusual items noted above, net earnings from the Gas Distribution businesses in 1999 were $125 million compared with $159 million in 1998 and $159 million in 1997. The reduction in earnings in 1999 reflects the January 1, 1999 transfer of assets related to Union Gas' retail merchandise and service programs to affiliates, with these earnings now reflected in the Services segment, and lower allowed rates of return on common equity for all of our distribution businesses.



Gas Distribution Customers(1)

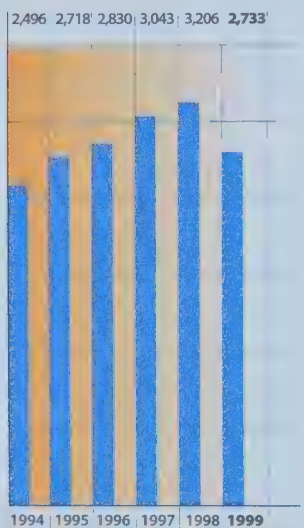
thousand

(1) includes Centra Gas Manitoba and Centra Gas Alberta until sold in 1999 and 1998, respectively.



Union Gas(1) Volumes

billion cubic feet



Union Gas(1)(2) Average Rate Base

$million

(1) includes Centra Gas Ontario Inc. which was amalgamated with Union Gas effective January 1, 1998

(2) On January 1, 1999, Union Gas transferred approximately $500 million of net assets to Westcoast Capital

The allowed rates of return on common equity are decided in each province by the respective provincial regulatory authority. The rates of return on common equity and the common equity components of the respective rate bases of the regulated businesses for 1997 to 1999 are outlined in note 1 to the consolidated financial statements.

The Company's Gas Distribution businesses are highly seasonal, with the majority of natural gas deliveries occurring during the winter heating season from mid-October to mid-April. Gas sales during this period typically account for approximately two-thirds of annual gas distribution revenues, resulting in strong first quarter results, second and third quarters that show either small profits or losses, and strong fourth quarter results.

Natural gas volumes delivered by the Gas Distribution businesses were:

Years ended December 31 (Bcf)	1999	1998	1997
VOLUMES			
Union Gas (1)	1,222	1,127	1,193
Centra Gas BC	26	23	24
PNG	39	36	39
Other	15	11	15
	1,302	1,197	1,271
Centra Gas Manitoba	42 (2)	63	67
Centra Gas Alberta	—	6 (3)	18
	1,344	1,266	1,356

(1) includes Centra Gas Ontario Inc. which was amalgamated with Union Gas effective January 1, 1998

(2) includes volumes until sold in July 1999

(3) includes volumes until sold in June 1998

The number of customers for the Gas Distribution businesses were:

As at December 31 (thousand)	1999	1998	1997
NUMBER OF CUSTOMERS			
Union Gas (1)	1,104	1,075	1,041
Centra Gas BC	66	61	55
PNG	39	39	38
Other	2	2	1
	1,211	1,177	1,135
Centra Gas Manitoba (2)	—	242	239
Centra Gas Alberta (3)	—	—	54
	1,211	1,419	1,428

(1) includes Centra Gas Ontario Inc. which was amalgamated with Union Gas effective January 1, 1998

(2) sold July 1999

(3) sold June 1998

Union Gas

In January 1998, Union Gas Limited and Centra Gas Ontario Inc. were amalgamated. The companies, which were both wholly owned subsidiaries of the Company, had operated under a shared services arrangement since 1994. The amalgamated company continues to carry on the Ontario distribution operations as Union Gas.

Union Gas distributes natural gas in Ontario. It also transports and stores natural gas for customers in Ontario, Quebec and the central and eastern United States. Union Gas' underground natural gas storage facilities have a working capacity of 131 Bcf and are the largest in Canada.

Following the approval of the OEB in May 1998, Union Gas transferred the operating responsibilities of its retail merchandise and service programs to Union Energy Inc. (Union Energy), an affiliated, non-regulated retail energy services business. This transfer occurred on January 1, 1999 when approximately $500 million of net assets were acquired by Westcoast Capital Corporation (Westcoast Capital) and Union Energy. The transferred retail merchandise and service programs include appliance sales and rentals, appliance service work and merchandise financing. Union Energy and Westcoast Capital, as non-regulated businesses, have more flexibility than the regulated utility to design and package energy products and services to meet customer needs. Union Gas continues to concentrate on developing and operating new services that emphasize cost effectiveness and reliability in the delivery of natural gas to customers.

The decrease in 1999 earnings compared with 1998 is primarily due to the transfer of the retail merchandise programs of Union Gas to Union Energy and Westcoast Capital ($18 million), and a lower allowed rate of return on common equity ($9 million). Earnings in 1999 also include an unusual expense related to business transformation initiatives.

This decrease was partially offset by colder weather in 1999 compared with 1998. Although colder than in 1998, the weather in 1999 was still warmer than normal. The unusually warm temperatures in 1998 are the primary reason for the reduction in earnings compared with 1997. Weather reduced earnings by $14 million and $35 million in 1999 and 1998, respectively, and increased earnings by $1 million in 1997.

Performance-Based Regulation

In March 1999, Union Gas filed an application with the OEB for approval of new rates that would be in accordance with a Performance-Based Regulation (PBR) mechanism. Negotiations are scheduled to take place in April 2000, with a hearing expected during the second quarter of 2000. The Company expects that the decision on the application will be effective as of January 1, 2000.

Centra Gas BC

In December 1995, the Company and the Province of British Columbia entered into an agreement replacing the previous financial arrangements relating to the natural gas pipeline to Vancouver Island and connected distribution systems.

For the years 1996 to 2002, the agreement provides for a deemed common equity component of rate base of 35% and a return on the common equity component of rate base of 3.625% over the Government of Canada long term bond rate. The agreement also provides for a reduction in the return on equity of approximately $2 million per year for the years 1996 to 2011, resulting in an effective rate of return on common equity of approximately 7.8% for 1999, compared with 8.6% in 1998.

The British Columbia Utilities Commission (BCUC) commenced a process in January 2000 to establish the long term cost allocation and rate design principles that Centra Gas BC will employ commencing in 2003.

PNG

PNG delivers gas to customers in west central British Columbia and through its subsidiary, Pacific Northern Gas (N.E.) Ltd., to customers in the province's northeast. Four large industrial customers in the petrochemical, pulp, and aluminum businesses account for approximately 74% of total gas deliveries.

The rate of return on common equity for PNG, as determined by a formula approved by the BCUC, was 10.00% for 1999 compared with 10.75% for 1998, on a common equity component of rate base of 36%.

Other Gas Distribution Businesses

Centra Gas Manitoba

In July 1999, the Company sold Centra Gas Manitoba to Manitoba Hydro for $245 million, resulting in an after-tax contribution to net income of $59 million, or 52 cents per common share. Consequently, the earnings for 1999 include the earnings of Centra Gas Manitoba to the date of completion of the sale. Earnings in 1998 reflect the non-recurring impact of the MPUB decision to disallow the recovery of certain natural gas costs related to price management activities. In June 1998, the MPUB approved the recovery of $19 million and disallowed the recovery of $27 million of approximately $46 million of natural gas costs related to price management activities. Of the $27 million of disallowed natural gas costs, $9 million was recovered from brokers serving the direct purchase market.

The impact of the disallowance, net of recoveries, related items and income taxes is a net reduction to 1998 earnings of approximately $12 million, or 12 cents per common share.

Centra Gas Alberta

In June 1998, the Company sold Centra Gas Alberta to AltaGas Services Inc. for $61 million, resulting in an after-tax contribution to net income of $14 million or 14 cents per common share.

Gas Distribution Statistics

The average rate bases and capital expenditures for the Gas Distribution businesses for 1999 and projected for 2000 are:

Years ending December 31 ($million)	2000	1999
RATE BASE		
Union Gas	2,847	2,733
Centra Gas BC	433	400
PNG	177	170
Other	25	21
	3,482	3,324

Years ending December 31 ($million)	2000	1999
CAPITAL EXPENDITURES		
Union Gas	258	222
Centra Gas BC	38	38
PNG	11	11
Other	—	22
	307	293

Gas Distribution Outlook

Regulatory

The Gas Distribution businesses are being affected by the trend to deregulation and competition. The companies are taking action to manage the risks and benefits from the opportunities presented under deregulation including the implementation of performance-based methods of regulation. Individually and collectively, the Gas Distribution businesses are working to ensure allowed returns on equity are commensurate with the risks of a changing industry.

As noted previously, Union Gas has applied for a performance-based method of regulation to be applicable to its regulated storage, transmission and distribution services in Ontario. PBR provides service, rate and value flexibility to customers and allows Union Gas to participate in the benefits of cost efficiencies and new service offerings.

With a change to full cost of service based regulation in 2003, Centra Gas BC is working with the BCUC and its customers to consider the appropriateness of cost allocation methodologies, rate design principles, and long term tolling implications. The result will be a framework that allows for competitive rates, fair shareholder treatment, and the consideration of appropriate PBR mechanisms.

Capital expenditures

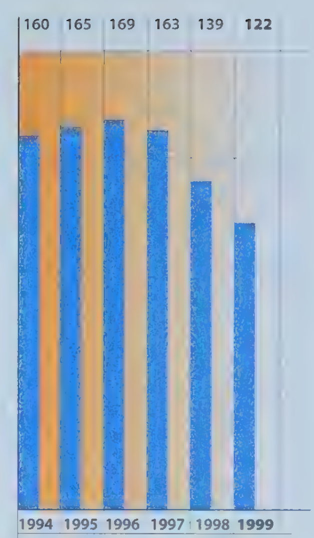
Capital expenditures in 1999 were $293 million. The Gas Distribution businesses expect to spend approximately $307 million on capital expenditures in 2000, an increase of $14 million from 1999.

Gas Distribution Business Risks

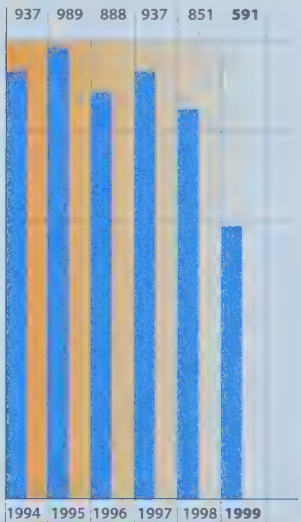
Union Gas has approximately 450 franchise agreements with municipalities in Ontario. These agreements set out the terms and conditions under which Union Gas conducts its business within the municipality. The model franchise agreement is being negotiated with the association of municipalities. Two municipalities have not renewed their franchise agreements with Union Gas resulting in an application by Union Gas to the OEB for renewal of these franchises.

For Centra Gas BC, the recovery of the accumulated revenue deficiency is a matter of significant importance to Centra Gas BC's long term financial viability. Shareholder recovery of funded revenue shortfalls will be sought over as short a period as possible, while balancing the impacts on customer rates and the continued need to provide a competitively priced service.

A new marine crossing to Vancouver Island to be completed by 2002, and owned and operated by BC Hydro and Williams Pipeline Co., has recently been announced. This new pipeline will increase the security of supply to the Island, and will provide the long-term capacity to supply planned cogeneration facilities on Vancouver Island. Centra Gas BC is currently working with both BC Hydro and Williams Pipeline Co. on the necessary service contracts, tolling agreements, and interconnect agreements.



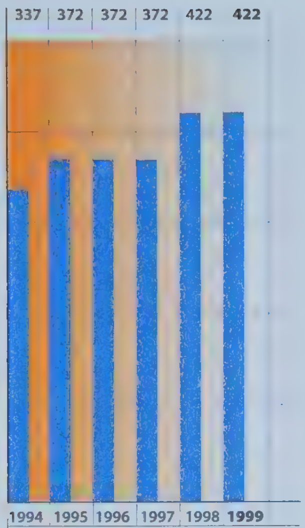
Other Gas Distribution Volumes(1)



Other Gas Distribution Average Rate Bases(1)

$million

(1) includes Centra Gas Manitoba and Centra Gas Alberta until sold in 1999 and 1998, respectively.



Power Generation Plant Capacity

megawatts

PNG faces risks associated with extending or renewing long term transportation service agreements with two of its large industrial customers, Methanex Corporation (Methanex) and Skeena Cellulose Inc. (Skeena). World prices for methanol remained at low levels throughout 1999. Methanex has stated that it wishes to reduce costs at its higher-cost plants, including the plant in Kitimat, and that it is seeking substantial reductions in its gas transportation costs. In June 1999, Methanex announced it had entered into a letter of intent with Acetex Corporation to transfer ownership of its Kitimat methanol facilities to Acetex for $1 and other considerations. The transfer has yet to be completed. Methanex recorded a US $55 million write-off of its Kitimat methanol facility in 1999. PNG is currently engaged in discussions with Methanex regarding mutually acceptable modifications of gas delivery contracts. PNG's long term transportation service and sales contract with Skeena matured in 1999, and is now in the first year of an evergreen one-year renewal. Discussions with Skeena are underway concerning a long-term extension of the contract.

POWER GENERATION

The Company has interests in five operating natural gas fired cogeneration plants in Canada and is developing additional projects.

The contribution to net earnings for Power Generation was:

Years ended December 31 ($million)	1999	1998	1997
NET INCOME CONTRIBUTION	11	6	11

Fiscal 1999 results reflect the sale of our 50% interest in the Fort Nelson powerline, resulting in an after-tax gain of $3 million.

The decrease in the contribution to net earnings for Power Generation in 1998 over 1997 is primarily due to the shut down in 1998 of the Fort Frances Cogeneration Plant due to a labour strike at Abitibi-Consolidated Inc., the steam host facility.

Island Cogeneration Project

The Island Cogeneration Project, a 250-megawatt cogeneration plant under construction at Fletcher Challenge Canada Limited's pulp and paper mill near Campbell River on Vancouver Island, British Columbia, is over 85% complete. The plant is expected to begin commercial operation in the third quarter of 2000.

All of the electric power output of the plant will be sold under a 20-year electricity purchase agreement with BC Hydro.

Bayside Power Project

In April 1998, Westcoast Power signed an agreement with New Brunswick Power Corporation (NB Power) of New Brunswick to proceed with development efforts to convert a 100-megawatt heavy fuel oil fired generating plant located in Saint John, New Brunswick, into a 285-megawatt natural gas fired combined cycle plant.

Under the agreement, the Company will provide the required equity and arrange project financing for the $180-million conversion, consisting of direct capital costs of $160 million, with NB Power providing $21 million for in-plant refurbishment and interconnection costs which they will lease to the Bayside Power Project. NB Power will contract to purchase the electric power output in the winter months. The Company will have the opportunity to export the electric power to the United States during the balance of the year.

Construction is approximately 40% complete, and the plant is expected to begin commercial operation during the first quarter of 2001.

Discussions are underway to sell a 25% share in the Bayside Power Project to Irving Oil.

Frederickson Power Project

The Company has entered into an agreement with Bonneville Power Authority to purchase a partially constructed 250-megawatt, combined cycle gas fired power generation plant located between Tacoma and Olympia in the State of Washington. This project is expected to commence commercial operation in mid-2002. Closing of the site and infrastructure acquisition is subject to completion of project permitting and site due diligence, and is expected to occur in the second quarter of 2000.

Liberty Electric Power Project

The Company has sold its 50% interest in the proposed 500-megawatt Liberty Electric Power Project near Philadelphia, Pennsylvania, to Columbia Electric, the primary developer of the project.

Power Generation Outlook

Demand for electric power continues to grow in North America. The growth in demand is particularly strong in the United States Pacific Northwest and Midwest market areas in, or near, markets currently served by the Company's natural gas operations. Peak electrical demand in the areas targeted by the Company as strategic regions is forecasted by the North American Reliability Council to grow by 40,000 megawatts by 2005. The Company will continue to develop, construct and operate power generation through targeted investments in base load and peaking plants in Canada and the United States.

Capital expenditures

Capital expenditures in 1999 were $148 million. The Power Generation businesses expect to spend approximately $173 million on capital expenditures in 2000, an increase of $25 million from 1999. Capital expenditures during 1999 and 2000 relate primarily to the construction of the Island Cogeneration and Bayside Power projects. The Company is currently reviewing its options to meet power business funding requirements during 2000.

Power Generation Business Risks

As the power industry continues to deregulate, the commercial risk to which power producers will be exposed will continue to increase. Generating companies will have

the choice of accepting market risk in anticipation of greater profits, or passing this risk on to wholesale and/or retail power customers under contract.

Westcoast Power currently contracts all output to creditworthy counterparties. Long-term agreements for gas supply and power sales are in place with occasional provisions for resetting contract pricing points to market levels, subject to certain limitations. The Bayside Power Project, currently under construction, has a portion of its power sales open for delivery to the New England Power Pool at market prices. Prior to commissioning this facility, Westcoast Power will assess whether it is economically more attractive to sell this power under contract to a power buyer or sell directly into the market. Engage Energy, the Company's marketing and trading affiliate, is working with Westcoast Power in determining the attractiveness of market pricing and providing the risk management capabilities needed for merchant power sales.

INTERNATIONAL

The operating business included in this business segment is a power generation facility located in Irian Jaya, Indonesia. In addition, this business segment includes two projects under development in Mexico and one project in China.

The contribution to net earnings for International was:

Years ended December 31 ($million)	1999	1998	1997
NET INCOME CONTRIBUTION	15	16	5

Fiscal 1999 and 1998 net income applicable to common shares reflect higher earnings from the Irian Jaya power investment as a result of a full year of contribution from a 1998 expansion of the power facilities and an increase in the Company's ownership in the plant from 20% to 43% in December 1997. Results in 1998 include the $8 million gain on the sale of the Company's interest in the Australian Eastern Gas Pipeline Project.

Indonesia – Irian Jaya Power Plant

P.T. Puncakjaya Power (PJP) owns and operates an integrated power generation plant, a related transmission line and associated facilities and provides electrical power to the Grasberg mine under a long-term contract payable in United States dollars in the United States. The total generating capacity of the PJP facilities is approximately 388 megawatts.

Mexico - Cantarell Nitrogen Project

The Company has a 20% interest in the Cantarell Nitrogen Project. The project facilities, which are expected to cost approximately $1.5 billion, will sell nitrogen under a long-term take or pay agreement with Pemex Exploración y Producción (PEP), a subsidiary of the national oil company of Mexico, to enhance the production and recovery of oil from the Cantarell oil field located in the Bay of Campeche, Gulf of Mexico.

Construction of the Cantarell Nitrogen Project is nearing completion with overall progress at about 95%. The first nitrogen production train is expected to begin operation during the second quarter and all four trains are projected to be onstream by the fourth quarter of 2000.

Limited recourse financing for $904 million of the estimated $1.5 billion total project cost was secured in September 1999. As of February 1, 2000, the shareholders have contributed $457 million to the Cantarell Nitrogen Project. The Company's share of this Cantarell investment is $93 million.

Mexico - Campeche Natural Gas Compression Services Project

In August 1998, an international consortium, in which the Company has a 45% interest, was awarded a 5-year take or pay contract by PEP to provide 250 MMcf/d of offshore natural gas compression and liquids recovery services on a platform in the Cantarell oil field in the Bay of Campeche, Gulf of Mexico. The consortium will construct, own and operate the platform which has an estimated cost of $420 million.

Progress on the overall project is approximately 65% complete. The engineering, procurement and construction contractor retained for the project has encountered certain construction problems, as a result of which the in-service date for the facility has been delayed beyond the contract completion date. The project is now expected to be brought into service in mid-2000.

Discussions with the customer, PEP, to obtain an extension to the contract in-service date are underway.

China - Shanghai Power Project

The Company has a 32.5% interest in a captive power project to produce 50 megawatts of electrical power at the Shanghai No.1 Iron & Steel (Group) Company Ltd. facilities in China. The plant, which uses blast furnace gas, a waste product, as its primary fuel, is expected to cost approximately $75 million.

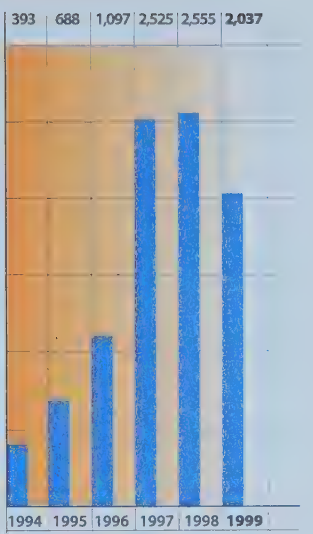
The 50-megawatt power project is currently scheduled to commence full commercial operation during the early part of the second quarter of 2000.

Australia - Eastern Gas Pipeline Project

In December 1998, the Company sold its 50% interest in the Eastern Gas Pipeline Project to a subsidiary of Duke Energy for approximately $27 million. The disposition resulted in a contribution to 1998 net earnings of $8 million after tax, or 8 cents per common share.

International Outlook

Given the considerable opportunities available to the Company in North America and the increase in risk associated with international markets recently, the Company has focused its international development activities on the Mexican energy market. Given Mexico's status under the North American Free Trade Agreement, and the integration of its energy market into the North American energy market, Mexico is seen as an attractive market and an important component in broadening the Company's North American presence in the energy industry.



Energy Marketing Natural Gas Marketed

billion cubic feet

Energy Marketing Electric Power Marketed

million megawatt hours

International Business Risks

The Company's international investments are subject to risks associated with foreign operations such as country, political, inflationary and foreign exchange risks, as well as risks particular to specific projects. The Company seeks to manage these risks by sharing risk through joint ventures, and by denominating revenues in United States dollars. The Company's investments in Indonesia and Mexico are based on contracts denominated primarily in United States dollars, therefore substantially sheltering the Company from local inflationary impacts and currency fluctuations in those countries.

SERVICES

Included in this business segment are businesses that provide energy marketing, retail energy services, information technology and financial services. These services are provided by Engage Energy Canada, L.P. and Engage Energy U.S., L.P. (collectively Engage Energy), Union Energy, Westcoast Capital, Enlogix Inc. (Enlogix) and NGX Canada Inc. (NGX).

The contribution to net earnings for Services was:

Years ended December 31 ($million)	1999	1998	1997
NET INCOME (LOSS) CONTRIBUTION			
Energy Marketing	4	(34)	(9)
Union Energy	(38)	(12)	(5)
Westcoast Capital	8	—	—
Enlogix	(8)	(1)	—
NGX	2	1	(1)
	(32)	(46)	(15)

The net loss for 1999 reflects improved results from the energy marketing business compared with 1998 and 1997, and earnings generated by Westcoast Capital. These results were offset by higher losses incurred by Union Energy, including certain unusual adjustments. Results in 1998 reflected the Company's share of an unusual loss of $14 million after tax due to customer defaults at Engage Energy.

Energy Marketing

Results for 1999 reflect the adoption of mark-to-market accounting, effective January 1, 1999, for the Company's energy marketing operations. The cumulative effect of the initial adoption of mark-to-market accounting at January 1, 1999, offset by the unamortized energy contracts purchased to equalize the Company's ownership in Engage Energy, has been recorded as a charge totalling $36 million against retained earnings.

Engage Energy contributed net earnings in 1999 of $5 million, compared with a net loss of $26 million in 1998 and minimal income in 1997. Engage Energy achieved improved results from structured natural gas and power transactions, improved management of risk capital and a continued emphasis on cost containment.

The 1998 results of Engage Energy include an unusual charge. In late June 1998, unusual and prolonged hot weather, combined with forced electrical outages, led to electricity price spikes that resulted in two of Engage Energy's customers defaulting on their obligations to deliver electricity. To meet its own sales commitments, Engage Energy was required to purchase replacement electricity in the market at substantially higher prices resulting in an unusual loss, of which the Company's proportionate after-tax share was $14 million, or 14 cents per common share.

Operating results from Engage Energy for 1998 were also impacted by substantially warmer than normal weather. Lower winter prices, reduced price volatility and competitive market conditions resulted in compressed margins for Engage Energy's natural gas trading activities in the United States.

Other contributing factors to the $34 million net loss incurred by the energy marketing business in 1998 include losses on firm capacity contracts related to the Kern River and Northwest Pipelines, which have been marked to market effective January 1, 1999, and the amortization of the energy contracts purchased to equalize the Company's ownership in Engage Energy. As noted above, with the adoption of mark-to-market accounting, these unamortized energy contracts of $58 million have been charged to retained earnings at January 1, 1999, eliminating the annual amortization expense in 1999 and in future years.

Union Energy

Union Energy, formed in 1997, provides energy equipment sales, rentals, installations and maintenance, as well as financing and energy management, procurement and sales to residential, commercial and industrial customers.

During 1998, Union Energy proceeded to pursue its non-regulated retail energy services business and continued to pursue growth through the acquisition of HVAC operations. To date, a total of 28 HVAC operations with annual revenues of approximately $82 million have been acquired in Ontario, Manitoba and British Columbia. These purchases were part of a program of assembling leading HVAC operations in major markets to take a leadership role in providing non-regulated energy services.

On January 1, 1999, Union Energy assumed operating responsibility for certain business and assets from Union Gas in retail merchandise and service programs. These net assets relate to appliance sales and rental programs, appliance service work and merchandise financing.

The 1999 results of Union Energy reflect a number of factors associated with the retail merchandise and energy services business acquired from Union Gas, including start-up costs, unusual charges and lower sales and service revenues as a result of transitional problems. Company management continues to focus considerable resources on improving the profitability of the entire business. To date, steps are underway to upgrade the Company's business processes and systems which have resulted in the need for certain unusual after-tax adjustments in 1999 of $18 million. These include provisions for write-offs of computer equipment, software and inventory, and an increase to the bad debt reserve. Furthermore, the

Company's rental assets are being depreciated based on a more conservative expected life, which gives rise to a greater depreciation charge. The net loss incurred in 1998 was primarily related to start-up costs associated with the formation of Union Energy.

Westcoast Capital

Westcoast Capital was established in April 1997 to provide selected financial services to complement the Company's other product offerings. Westcoast Capital's business is largely focused on energy-related investments and is divided into two distinct sectors, Retail Finance and Commercial and Industrial Finance. The Retail Finance business includes the financing and rental of household appliances to individual homeowners while the Commercial and Industrial Finance business includes the financing of capital equipment for businesses.

The contribution to net earnings from Westcoast Capital for the year ended December 31, 1999 was $8 million compared with minimal income in 1998. The increase in earnings is primarily related to the acquisition of the majority of the assets of Union Gas' retail merchandise finance and rental programs on January 1, 1999.

The portfolio of financial assets includes both a significant retail portfolio and a number of commercial and industrial transactions. The growth of Westcoast Capital's Commercial and Industrial Finance portfolio continued through 1999 as the Company closed 20 transactions involving $32 million of investments in oil gathering and processing, gas compression, and industrial equipment and volumetric prepayments.

In December 1999, Westcoast Capital sold certain of its asset-based finance contracts to a securitization vehicle. The transaction resulted in the removal of the finance contracts from the Company's balance sheet and the recording of assets received, which included cash of $74 million. The proceeds approximated net book value.

Enlogix

The Enlogix Group provides billing and customer information services, through Enlogix CIS, and meter reading services, through IntraLynx, to the utility sector. In 1999, Enlogix CIS successfully completed installations for 6 clients and is now in operation serving 2.2 million customers. This number will grow to 3 million customers with the installation for Union Gas' southern operations scheduled for the second quarter of 2000. Enlogix has emerged as a leading North American provider of these services.

IntraLynx completed its first year of operation in 1999. It sold meter reading services to 20 new utility clients and launched outsourced automatic meter reading services for 28,000 Union Gas customers in Sarnia.

The Enlogix Group incurred a net loss applicable to common shares of $8 million for the year ended December 31, 1999, compared with a net loss of $1 million in 1998. Fiscal 1999 results are lower compared with 1998 as all Enlogix CIS product development costs were capitalized for most of 1998. Enlogix CIS became operational in the fourth quarter of 1999.

NGX

NGX provides electronic natural gas trading services at the Alberta and Empress market centres in Western Canada. On February 10, 2000 the Company announced its intention to sell 51% of its natural gas exchange operation to OM Gruppen of Sweden, one of Europe's leading electronic exchange owners and operators. The terms of the agreement allow the Company to sell the remaining 49% of NGX to OM Gruppen at a future date. The sale of 51% of NGX is expected to result in an after-tax gain of approximately $7 million in 2000. The transaction is expected to close at the end of the first quarter of 2000.

Services Outlook

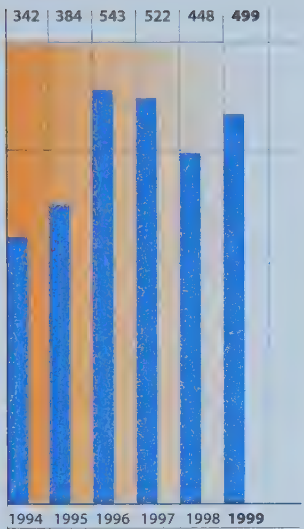
Market opportunities are developing to provide energy services in addition to the traditional transmission and distribution of natural gas. These opportunities include merchandizing, service, rental and financing/leasing opportunities for end-use retail energy customers as well as risk and supply management services to wholesale customers such as other utilities or large industrial customers. Demand for information-based services is also developing in all of these markets. Recently, Enlogix introduced web-based services to provide its customers with e-commerce solutions.

New energy services businesses, established outside of the regulatory framework, are being developed. Engage Energy, Union Energy, Westcoast Capital and Enlogix are new and developing businesses that are planned to fill customer service needs in the wholesale and retail energy services and information services areas.

Services Business Risks

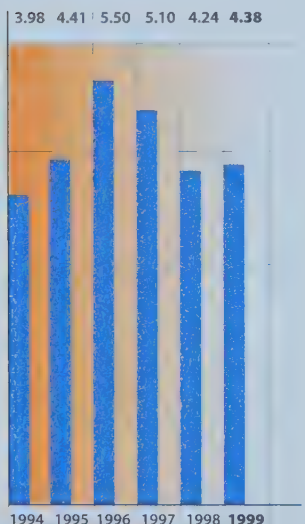
Energy Marketing Risk Management

Energy marketing operates in a competitive environment characterized by volatility and narrow margins. Engage Energy operates an energy merchant and trading business, in which its portfolio of physical and financial forward transactions has inherent market, credit and operations risks. The Company's risk management practices define in a clear and consistent fashion, the methodology employed in measuring risks and the maximum risk exposure on any one day. The risks of the Company's energy marketing portfolio are monitored by an internal risk management group independent of energy trading activities to ensure compliance to Company standards. The Company monitors and manages its exposure to market risk through a variety of risk management techniques. Such procedures include measurement of risk, market comparisons, monitoring of all commitments and positions, and daily reporting to senior management. In addition, sensitivity to changes in market price and market volatility are examined on a daily basis. The Company utilizes derivative and other



Operating Cash Flow

$million



Operating Cash Flow per Common Share

dollars

financial instruments in connection with both trading and non-trading activities. The Company enters into forward, future, swap and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments.

Interest Rate Risk

Interest rate risk is the risk that costs associated with funding fixed rate leasing and financing contracts will change, either favourably or unfavourably, in response to changing debt market conditions. This risk is monitored and, where deemed appropriate, various swap and hedging products are utilized to minimize losses to the portfolio of investments.

Credit Risk

In connection with the market valuation of its energy trading, leasing and finance contracts, the Company maintains certain reserves for a number of risks and costs associated with these future commitments. Among others, these include reserves for credit risks based on the financial condition of counterparties, reserves for product location differentials and consideration of the time value of money for long-term contracts. Credit risk is the risk of loss from non-performance by suppliers, customers or financial counterparties to a contract. The Company maintains credit policies, which management believes significantly minimize overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure, monitoring of aggregate exposure against limits by the internal credit risk management group and the use of standardized agreements which allow for the netting of positive and negative exposures associated with a single counterparty. The credit risk management group reviews and monitors the application of these policies for suppliers, customers and counterparties. Customers not meeting minimum standards must provide secured credit terms.

Financial instruments are described in note 17 to the consolidated financial statements.

OTHER

This business segment includes corporate expenses, business development expenditures, corporate financing expenses and utilization of previous years' unrecorded tax losses.

The contribution to net earnings for Other was:

Years ended December 31 ($million)	1999	1998	1997
NET INCOME (LOSS) CONTRIBUTION			
Corporate financing	(63)	(65)	(51)
Business development	(11)	(15)	(14)
Other	(6)	15	(1)
	(80)	(65)	(66)

Included in this balance are corporate financing expenses which include preferred dividends of $45 million, $36 million and $27 million in 1999, 1998 and 1997, respectively. Unallocated interest amounted to $18 million in 1999, relating to approximately $800 million of debt, compared with $29 million in 1998, relating to approximately $1,050 million of debt and $24 million in 1997, relating to approximately $900 million of debt. Results in 1998 include a foreign exchange gain of $9 million.

Corporate financing costs increased in 1998 over 1997 primarily due to higher financing costs as a result of having significant capital invested in projects under development, higher borrowings to fund increased capital expenditures and higher interest rates.

Business Development

TriState Pipeline Project

As a result of its participation in Vector, the Company has withdrawn from the TriState Pipeline Project, a competing proposal to transport natural gas from Chicago to the Dawn hub. The Company wrote off the balance of its investment in the TriState Pipeline Project amounting to approximately $3 million after tax in 1999.

Millennium Pipeline Projects

The Company has a 21% interest in the proposed Millennium Pipeline Project which is designed to deliver 700 MMcf of natural gas per day from southwest Ontario to New York City and other markets in the eastern United States. The 611-kilometre pipeline is expected to cost approximately $950 million.

The proposed Millennium West Pipeline Project, in which the Company has a 100% interest, is a proposed $165-million, 75-kilometre pipeline from Union Gas' existing pipeline system and storage facilities at Dawn, Ontario to the shore of Lake Erie northwest of Patrick Point, Ontario. The Millennium West Pipeline Project is intended to interconnect with another proposed pipeline that would cross Lake Erie to connect to the proposed Millennium Pipeline Project.

The Company and its partners continue to pursue regulatory approvals and shipper transportation agreements for the proposed Millennium Pipeline and Millennium West Pipeline projects.

LIQUIDITY AND CAPITAL RESOURCES

Cash Generated from Operations

Cash generated from operations was $456 million for the year ended December 31, 1999, compared with $502 million and $520 million in 1998 and 1997, respectively. The decrease in cash generated from operations in 1999 is attributable to certain non-cash items included in income in 1999, including the gains on the sale of Centra Gas Manitoba and Fort Nelson powerline.

The contribution to consolidated operating cash flow after non-cash working capital changes by business segment was:

Years ended December 31 ($million)	1999	1998	1997
CASH FLOW FROM OPERATING ACTIVITIES			
Transmission & Field Services	238	234	195
Gas Distribution	246	283	328
Power Generation	25	25	31
International	38	30	2
Services	14	(65)	3
Other	(62)	(59)	(37)
Operating cash flow	499	448	522
Non-cash working capital changes	(43)	54	(2)
	456	502	520

Investing Activities

In 1999, capital expenditures and investments totalled approximately $1.5 billion. Capital expenditures amounted to $1,305 million in 1999 compared with $911 million in 1998 and $690 million in 1997. The majority of capital spending in fiscal 1999 related to the two new pipeline projects, Maritimes & Northeast Pipeline and Alliance Pipeline, and the Island Cogeneration Project. The increase in 1998 capital expenditures compared with 1997 was primarily due to higher activity with respect to projects under development such as the Maritimes & Northeast Pipeline, the Cantarell Nitrogen Project, the Campeche Natural Gas Compression Services Project and the Shanghai Power Project.

The Company's planned capital spending for 2000 is currently projected to total $1.3 billion, however, future years' expenditures are dependent on conditions in the energy industry. The planned 2000 expenditures are primarily intended for the completion of projects currently under development and for operational requirements. The Company anticipates that virtually all of its capital commitments can be met from internally generated funds, capital redeployments and accessing debt markets.

The Company's 1999 acquisitions include the purchase of 13 HVAC businesses and a 30% interest in Vector. Acquisitions in 1998 consisted of the acquisition of 15 HVAC businesses, and additional interests in both the Alliance Pipeline and Island Cogeneration Project, while 1997 reflects the acquisition of an additional interest in P.T. Puncakjaya Power. Investing activities in 1999 also reflect cash provided by the disposition of Centra Gas Manitoba, our interest in the Fort Nelson powerline joint venture, and the sale of certain asset-based finance contracts by Westcoast Capital. Investing activities in 1998 reflect the sale of our interest in the Australian Eastern Gas Pipeline Project and Centra Gas Alberta.

Financing Activities

In 1999, a concern developed about the emerging difficulty of attracting capital to the pipeline and utility sector at an appropriate cost in order to fund growth. Regulators at the national and provincial level have, over the past few years, reduced the approved rates of return for the regulated utility parts of our Company and our industry. The rates of return prescribed by regulators in Canada are significantly lower than those in the United States and lower than the market suggests is necessary to attract future investment capital to the pipeline and utility sector.

The Company, its subsidiaries and joint ventures have the ability to draw on operating lines of credit in excess of $1,700 million with commercial banks. These operating lines of credit enable the Company, its subsidiaries and joint ventures to borrow directly from the banks, to issue bankers' acceptances and to support commercial paper programs. In December 1997, $600 million of short term operating lines of credit were converted to a 5-year term operating line of credit.

The Company, its subsidiaries and joint ventures make use of short term indebtedness to finance working capital as well as provide interim financing in advance of long term debt or equity issues. At times, the resulting consolidated short term indebtedness and the portion of long term debt due within one year result in negative working capital.

In 1999, from the issuance of long term debt, preferred shares and common equity, the Company, its subsidiaries and joint ventures raised cash of $1,083 million (1998 – $1,484 million; 1997 – $433 million). In June 1999, the Company raised $150 million from the issue of 6,000,000 5.6% Cumulative First Preferred Shares, Series 8. In October 1999, the Company raised $125 million from the issue of 5,000,000 5.0% Cumulative Redeemable First Preferred Shares, Series 9. The Company also redeemed 5,000,000 6.9% Cumulative Redeemable First Preferred Shares, Series 4, for an aggregate redemption price of $125 million plus accrued dividends in October 1999.

The Company issues common shares through its Dividend Reinvestment and Share Purchase Plan. Common shares issued under the plan increased common stock by $55 million in 1999 compared with $51 million in 1998 and $52 million in 1997.

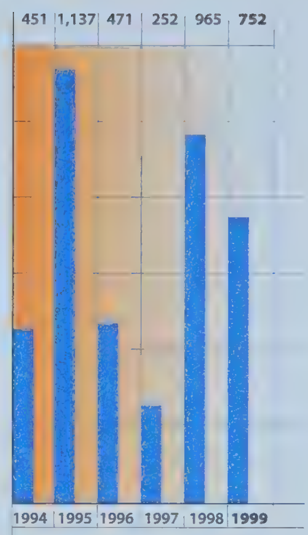
Details of long term debt, preferred share issues and common share issues are provided in notes 4, 14, and 15, respectively, to the consolidated financial statements.

TAXATION

In addition to federal and provincial income taxes, the Company's operations are subject to significant indirect taxation. The amount of taxes paid by the Company and its subsidiaries in 1999 was $294 million or 55% of income before income taxes, indirect taxes and non-controlling interest.

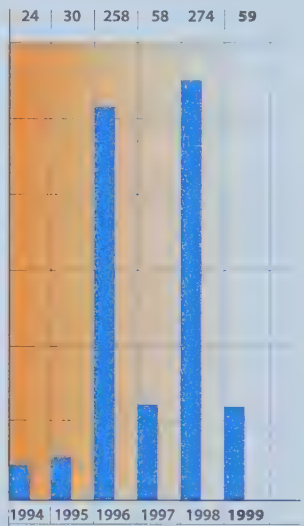
The types of taxes paid are:

Years ended December 31 ($million)	1999	1998	1997
TAXATION			
Federal, provincial and state income taxes	60	108	144
Large corporation tax	19	17	14
Current income taxes	79	125	158
Property taxes	124	126	117
Provincial, state, capital and sales taxes	48	44	41
Payroll related taxes	23	24	23
Natural gas taxes	16	17	17
Other taxes and permits	4	4	6
	294	340	362



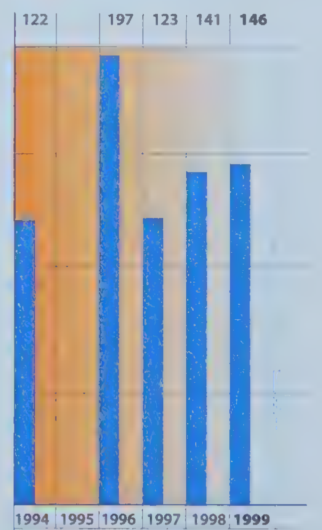
Long Term Debt Issued

$million



Common Shares Issued

$million



Preferred Shares Issued (net)

$million

YEAR 2000 REVIEW

The Year 2000 issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The Company, its subsidiaries and joint ventures have made the transition to the year 2000 without incident. The Company is continuing to monitor its systems for date related issues. Although the change in date has occurred and no evidence of any issues has been detected, it is not possible to conclude that all aspects of the Year 2000 issue that may affect the entity, including those related to customers, suppliers or other third parties, have been fully resolved. The total costs related to the Company's Year 2000 Project were $48 million. The impact of the Year 2000 program and contingency costs on 1999 annual earnings applicable to common shares was approximately $13 million (1998 – $6 million).

NEW ACCOUNTING PRONOUNCEMENTS

Income Taxes

In December 1997 the Canadian Institute of Chartered Accountants (CICA) issued a new standard, Section 3465 of the CICA Handbook "Income Taxes," which requires the liability method of accounting for income taxes. It changes the focus from income statement timing differences to balance sheet temporary differences. Under the new standard, tax assets and liabilities are measured using income tax rates and applying tax laws that will apply to taxable income in the period when the tax assets or liabilities are expected to be realized or settled. In addition, the criteria used to recognize tax losses for accounting purposes will be less restrictive.

The new standard is effective for fiscal years beginning on or after January 1, 2000, although rate-regulated entities may continue to use the method prescribed by the regulatory authorities. While early adoption is permitted, the Company will adopt the standard in fiscal 2000. The new rules will be applied retroactively. Although restatement is encouraged, it is not required, and the Company will not be restating the comparative periods presented. The Company continues to evaluate the impact of adopting Section 3465 and expects to recognize a charge to retained earnings in the first quarter of 2000.

Post-Retirement Benefits

In March 1999 the CICA issued a new standard, Section 3461 of the CICA Handbook "Employee Future Benefits," which modifies the current CICA Handbook requirements for pension costs and obligations and applies these requirements to non-pension benefits. Under the new standard, the Company will replace pay-as-you-go accounting for post-retirement benefits other than pension with accrual accounting that recognizes the liability and expense for the period when the benefits are earned, not received.

The new standard, applicable for fiscal years beginning on or after January 1, 2000, with the option of early adoption, will be adopted by the Company in fiscal 2000. The recommendations can be implemented either prospectively, with amortization of the transitional amount over the expected average remaining service life, or retroactively with prior year restatement. If applied retroactively, a cumulative adjustment to retained earnings could be made rather than restating each individual prior year. The Company will be adopting the new standard prospectively. The Company continues to evaluate the impact of adopting Section 3461 and expects to recognize an increase in employee future benefit expense.

MARKET OUTLOOK

Supported by plentiful supply, growing demand and additional transportation infrastructure, the North American natural gas industry continues to have a positive future as natural gas remains an environmentally acceptable, cost effective energy choice for consumers and industry.

Demand growth is expected to continue to be robust as a result of base economic growth, and from the increasing use of natural gas to power electric generation. Longer term, the development of fuel cell technologies also supports an optimistic outlook for the industry since natural gas is one of the main fuel choices for this technology.

Supply of natural gas in North America is widely believed to be sufficient to meet the anticipated demand. The addition of considerable reserves on the Scotian Shelf, off of Atlantic Canada, has added a further economical supply source in close proximity to large markets in the United States. Exploration success in the northwestern portion of the Western Canadian Sedimentary Basin further supports a view that supply will be sufficient to meet North American needs into the future. As well, continued strong prices for natural gas are also supportive of the commercial development of known, plentiful reserves in the Arctic regions in the future.

Completion of major projects that add large amounts of new infrastructure at one time can result in short term capacity imbalances leading to temporary weak pricing situations. Continued demand growth will allow these imbalances to be corrected in a fairly short period of time as growing markets absorb the incremental capacity.

The regulatory and competitive environment is evolving and the Company is changing its business practices to meet these changes and maintain its competitive position in its markets.

The outlook for the Company's core business units continues to be positive, supported by growing demand for gas, plentiful supply, adequate infrastructure and strong environmental support for natural gas as an appropriate alternative to other fossil fuels and nuclear energy.

Management Responsibility for Financial Reporting

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in Canada and include certain estimated amounts which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon the Company's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the consolidated financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is composed solely of directors who are not employees of the Company or of its subsidiaries.

The Audit Committee meets regularly with management, the internal auditors and the shareholders' auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

Ernst & Young LLP, Chartered Accountants, the shareholders' auditors, have full and free access to the Audit Committee, as does the Director of Internal Audit Services. The Audit Committee reports its findings to the Board of Directors.

Ernst & Young LLP has performed an independent audit of the consolidated financial statements in this report. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Auditors' Report.

February 10, 2000

M.E.J. Phelps
Chairman and Chief Executive Officer

G.M. Wilson
Executive Vice President and Chief Financial Officer

Auditors' Report

To the Shareholders of Westcoast Energy Inc.

We have audited the consolidated balance sheets of Westcoast Energy Inc. as at December 31, 1999 and 1998 and the consolidated statements of operations, retained earnings and cash flow for each of the years in the three year period ended December 31, 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1999 and 1998 and the results of its operations and its cash flow for each of the years in the three year period ended December 31, 1999 in accordance with accounting principles generally accepted in Canada.

Ernst & Young LLP

Chartered Accountants
Vancouver, Canada
February 10, 2000

Consolidated Statements of Operations

For the years ended December 31

$million, except for share data	1999	1998	1997
OPERATING REVENUES	6,265	7,376	7,312
OPERATING EXPENSES			
Cost of sales	4,258	5,473	5,379
Operation and maintenance	826	731	663
Depreciation	401	364	329
Taxes — other than income taxes	157	158	148
	5,642	6,726	6,519
OPERATING INCOME	623	650	793
OTHER INCOME			
Allowance for funds used during construction	34	19	12
Investment and other income	172	80	23
	829	749	828
OTHER EXPENSES			
Interest (Note 4)	499	488	454
Other	7	9	6
	506	497	460
INCOME BEFORE UNDERNOTED ITEMS	323	252	368
INCOME TAXES (Note 7)			
Current	79	125	158
Deferred	(33)	(77)	(35)
	46	48	123
	277	204	245
NON-CONTROLLING INTEREST	10	6	7
NET INCOME	267	198	238
PROVISION FOR DIVIDENDS ON PREFERRED SHARES	45	37	28
NET INCOME APPLICABLE TO COMMON SHARES	222	161	210
COMMON SHARES — WEIGHTED AVERAGE (million)	114	105	102
EARNINGS PER COMMON SHARE — BASIC (Note 9)	$1.95	$1.53	$2.06
DIVIDENDS PER COMMON SHARE	$1.28	$1.26	$1.20

See accompanying notes

Consolidated Statements of Cash Flow

For the years ended December 31

$million, except for share data	1999	1998	1997
OPERATING ACTIVITIES			
Net income	267	198	238
Add (deduct) items to reconcile to net cash			
Non-controlling interest	10	6	7
Deferred income taxes	(33)	(77)	(35)
Depreciation and amortization	396	370	339
Net assets from price risk management activities	(13)	—	—
Equity earnings	(22)	(4)	—
Other	(106)	(45)	(27)
Operating cash flow	499	448	522
Non-cash working capital changes (Note 6)	(43)	54	(2)
	456	502	520
INVESTING ACTIVITIES			
Additions to fixed assets	(1,305)	(911)	(690)
Acquisitions (Note 11)	(39)	(137)	(122)
Dispositions (Note 12)	255	88	—
Investments and other	(48)	(85)	(63)
Net cash used by investing activities	(1,137)	(1,045)	(875)
FINANCING ACTIVITIES			
Increase (decrease) in bank indebtedness	102	(80)	360
Long term debt additions	809	916	252
Long term debt repayments	(240)	(586)	(208)
Preferred shares issued (Note 14)	272	145	123
Preferred shares redeemed (Note 14)	(126)	(4)	—
Common shares issued (Note 15)	59	274	58
Non-controlling interest preferred shares issued (redeemed)	—	100	(44)
Dividends paid	(191)	(170)	(150)
Dividends paid to non-controlling interest	(10)	(5)	(5)
Net cash provided by financing activities	675	590	386
INCREASE (DECREASE) IN CASH AND SHORT TERM INVESTMENTS DURING THE YEAR	(6)	47	31
CASH AND SHORT TERM INVESTMENTS, BEGINNING OF YEAR	107	60	29
CASH AND SHORT TERM INVESTMENTS, END OF YEAR	101	107	60
OPERATING CASH FLOW PER COMMON SHARE (Note 9)	$4.38	$4.24	$5.10

See accompanying notes

Consolidated Balance Sheets

December 31

$million	1999	1998
ASSETS		
CURRENT ASSETS		
Cash and short term investments	101	107
Accounts receivable		
Trade	890	928
Other	111	132
Assets from price risk management activities (Note 17)	111	—
Inventory	435	400
Prepayments	29	29
	1,677	1,596
INVESTMENTS (Note 13)	454	374
ASSETS FROM PRICE RISK MANAGEMENT ACTIVITIES (Note 17)	186	—
FIXED ASSETS (Notes 4 and 18)		
Plant, property and equipment	12,096	11,475
Less accumulated depreciation	2,988	2,906
	9,108	8,569
DEFERRED CHARGES AND OTHER ASSETS (Note 8)	352	281
	11,777	10,820

On behalf of the Board:

Director

Director

$million	1999	1998
LIABILITIES		
CURRENT LIABILITIES		
Bank indebtedness (Note 5)	779	677
Accounts payable and accrued liabilities		
Trade	737	656
Other	225	247
Income and other taxes payable	36	31
Liabilities from price risk management activities (Note 17)	100	—
Interest on debt	94	96
Long term debt due within one year (Note 4)	322	228
	2,293	1,935
LIABILITIES FROM PRICE RISK MANAGEMENT ACTIVITIES (Note 17)	175	—
LONG TERM DEBT (Note 4)	5,550	5,297
DEFERRED INCOME TAXES (Note 7)	333	340
NON-CONTROLLING INTEREST		
Preferred	130	129
Common	36	35
	166	164
PREFERRED SHAREHOLDERS' EQUITY		
PREFERRED STOCK (Note 14)	865	716
COMMON SHAREHOLDERS' EQUITY		
COMMON STOCK (Note 15)	1,755	1,695
CUMULATIVE TRANSLATION ADJUSTMENT (Note 21)	(1)	30
RETAINED EARNINGS	641	643
	2,395	2,368
	11,777	10,820

COMMITMENTS AND CONTINGENCIES (Notes 4, 10, 17 and 22)

See accompanying notes

Consolidated Statements of Retained Earnings

For the years ended December 31

$million	1999	1998	1997
RETAINED EARNINGS, BEGINNING OF YEAR	643	623	536
NET INCOME	267	198	238
Share issue costs (Notes 14 and 15)	(4)	(8)	(1)
Adoption of mark-to-market accounting (Note 1)	(36)	—	—
Transfer of retail services business (Note 2)	(38)	—	—
	832	813	773
DIVIDENDS			
Common shares	146	133	122
Preferred shares	45	37	28
	191	170	150
RETAINED EARNINGS, END OF YEAR	641	643	623

See accompanying notes

Notes to Consolidated Financial Statements

December 31, 1999

1. ACCOUNTING POLICIES

Accounting Principles

The Company is incorporated under the laws of Canada and prepares its financial statements in accordance with accounting principles generally accepted in Canada which, as applied in these financial statements except as described in note 20, conform in all material respects with accounting principles generally accepted in the United States. The consolidated financial statements are presented in Canadian dollars.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities.

Consolidation

The consolidated financial statements include the accounts of the Company, its subsidiaries and its proportionate share of joint venture investments.

Major Subsidiaries (a)
(wholly owned unless otherwise indicated)

Westcoast Gas Holdings Inc.
Westcoast Gas Inc.
UEI Holdings Inc.
Westcoast Gas Services Inc.
Centra Gas Holdings Inc.
Centra Gas Utilities Inc.
Union Gas Limited
Centra Gas British Columbia Inc.
Pacific Northern Gas Ltd. – 41% owned, including 100% of the voting shares
Westcoast Power Holdings Inc.
Westcoast Power Inc.
Westcoast Energy International Inc.
Westcoast Capital Corporation
Westcoast Energy Risk Inc.
NGX Canada Inc.
Enlogix Inc.

Major Joint Ventures

Foothills Pipe Lines Ltd. – 50% owned
Empire State Pipeline – 50% owned
Maritimes & Northeast Pipeline Limited Partnership – 37.5% owned
Maritimes & Northeast Pipeline, L.L.C. – 37.5% owned
Engage Energy – 50% owned (Note 13)
McMahon Cogeneration Plant – 50% owned
Lake Superior Power Limited Partnership – 50% owned
Whitby Cogeneration Limited Partnership – 50% owned
P.T. Puncakjaya Power – 43% owned (Note 11)
Cantarell Nitrogen Project – 20% owned
Campeche Natural Gas Compression Project – 45% owned (Note 10)

(a) In 1999 and 1998, respectively, the Company sold its wholly owned subsidiaries Centra Gas Manitoba Inc. and Centra Gas Alberta Inc. (Note 12)

Investments

Investments in which the Company exercises significant influence, but not control, are accounted for by the equity method. The Company's 23.6% interest in the Alliance Pipeline Projects and 30% interest in the Vector Pipeline Project are accounted for as equity investments (Notes 11 and 13). Other investments are carried at cost, net of write downs for declines in value that are other than temporary in nature. Finance contracts represent customer financing for the purchase of natural gas appliances which are due over periods of up to 10 years.

Gas Distribution Revenue Recognition

Operating revenues include gas sales applicable to the Gas Distribution businesses which are recorded on the basis of meter readings plus an estimate of customer usage since the last meter reading date prior to the end of the year.

Income Taxes

The Company and its subsidiaries provide for income taxes relating to utility businesses using the income taxes currently payable method as directed by the regulators. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items.

The income tax allocation method is used for non-utility businesses of the Company, its subsidiaries and certain utility items as directed by regulators. Under this method, provision is made for income taxes deferred principally as a result of claiming capital cost allowance for income tax purposes in excess of depreciation provided in the accounts.

Regulation

Certain operations of the Company are engaged in utility businesses which are subject to regulation by federal, provincial or state agencies within Canada and the United States. The regulatory authorities exercise statutory authority over matters such as rate of return, natural gas exports, construction and operation of natural gas facilities, accounting practices and rates, tolls and charges. The regulatory rates of return on common equity applicable to utility businesses are:

For the years ended December 31 (percent)

	Equity Component of Rate Base			Return on Common Equity		
	1999	**1998**	**1997**	**1999**	**1998**	**1997**
Westcoast Energy Inc.						
– Pipeline	30	30	30	(a)	(a)	(a)
– Field Services	38.6	38.6	38.6	(a)	(a)	(a)
Foothills Pipe Lines Ltd.	30	30	30	9.58	10.21	10.67
Empire State Pipeline	40	40	40	12.50	12.50	12.50
Union Gas Limited	35	34	34	9.61	10.53	11.00
Centra Gas Ontario Inc.	(b)	(b)	36	(b)	(b)	11.25
Centra Gas British Columbia Inc.	35	35	35	8.99	8.59	9.32
Pacific Northern Gas Ltd.	36	36	35	10.00	10.75	11.00
Maritimes & Northeast Pipeline	25	25	—	13–14	13–14	—
Alliance Pipeline Projects	30	30	—	11.20	11.20	—
Vector Pipeline Project	30	—	—	14.00	—	—

(a) In 1998, the Company and its major customers agreed to a framework for light-handed regulation of the gathering and processing facilities which are regulated by the National Energy Board. The framework became effective immediately upon approval by the NEB in June 1998.

The framework amends the multi-year incentive-based toll settlement applicable to the Company's gathering and processing services that was approved by the NEB in August 1997. The framework defines the principles under which the Company negotiates service contracts individually with new and existing shippers, including tolls applicable to gathering and processing services. Consistent with these principles, the Company is responsible for the utilization of its gathering and processing assets and, accordingly, tolls for service are no longer based on the cost of service method of regulation.

The multi-year incentive-based toll settlement approved in August 1997 provided gathering and processing shippers the option of contracting for fixed base tolls for 1, 3, or 5-year service for which the tolls reflect a 500 basis point reduction from the agreed upon rate of return on common equity and are subject to a monthly surcharge based on an index of monthly gas prices. The gas price sensitive monthly surcharge allows the Company the opportunity to recover the revenues associated with the 500 basis point reduction in return on common equity and the opportunity to earn additional revenues. As the 1, 3, or 5-year contracts expire, customers and the Company will negotiate replacement contracts under the framework for light-handed regulation.

Transmission services continue to operate under the multi-year incentive-based toll settlement (effective from 1997 to 2001) approved by the NEB in August 1997. The settlement provided transmission customers the option of contracting for

fixed tolls for 5-year service or tolls that are adjusted annually in accordance with a prescribed incentive-based methodology. Fixed tolls for 5-year service were based on a 10.67% return on common equity.

(b) Effective January 1, 1998, Union Gas Limited and Centra Gas Ontario Inc. were amalgamated, continuing operations as Union Gas Limited.

Foreign Currency

The Company's foreign businesses maintain their accounts in United States dollars or local currency. These businesses are operationally and functionally self-sustaining and accordingly, the assets and liabilities are translated into Canadian dollars at the year-end exchange rate, and revenues and expenses are translated into Canadian dollars at the average exchange rate for the year. The resulting unrealized cumulative translation gains or losses are deferred as a separate component of common shareholders' equity.

For development expenditures applicable to foreign businesses, costs are translated into Canadian dollars at the prevailing exchange rate as incurred.

Funds on deposit with banks and current liabilities payable in United States dollars have been translated into Canadian dollars at the year-end exchange rate. Any resulting gain or loss is reflected in income.

The Company enters into foreign currency swaps to manage certain foreign currency risks.

Cash and Short Term Investments

Short term investments, consisting of money market instruments with maturities of three months or less, are considered to be cash equivalents and are recorded at cost, which approximates current market value.

Fixed Assets

Plant, property and equipment are recorded at cost. In accordance with normal utility practice, the cost of utility plant, property and equipment includes an allowance for funds used during construction. For non-regulated businesses, interest costs incurred during construction are capitalized as part of the cost of the asset.

Assets employed in utility businesses are depreciated on the straight-line basis at rates approved by regulatory authorities. Power generation facilities are depreciated on a unit of production basis. Other non-utility assets are depreciated on the straight-line basis. The rates used resulted in a composite rate of 3.4% for the year ended December 31, 1999 (for the year ended December 31, 1998 – 3.3%, for the year ended December 31, 1997 – 3.2%).

For some of the Gas Distribution businesses, the regulators have authorized the recovery over time of anticipated future removal and site restoration costs. For the other utility businesses, the regulators have not yet directed that future removal and site restoration costs be accrued. Upon retirement or sale of items of utility plant, property or equipment, the original costs associated with such items are charged against the applicable accumulated depreciation accounts and the cost of removal net of proceeds of disposal are charged to accumulated depreciation.

The cost of fixed assets is reduced by contributions and grants in aid of construction received from customers and from governmental bodies in support of specific pipeline and distribution facilities.

Capitalization and Maintenance

Maintenance and repairs are charged to expense accounts when incurred. The costs of major replacements, extensions or improvements are capitalized as plant, property and equipment. For power generation facilities, provisions for major maintenance and gas turbine overhauls are normalized and accrued annually.

Inventory

Materials and supplies are valued at the lower of average cost or net realizable value. Natural gas inventories are valued at costs approved by the regulators.

Pension and Other Post Retirement Benefits

The Company maintains both defined contribution and defined benefit pension plans. For the defined contribution plan, contributions payable by the Company are expensed as pension costs. Pension costs and obligations for the defined benefit pension plans are determined annually by independent actuaries using management's best estimates and are charged to earnings as services are rendered. Pension assets are valued by using current market values or average market related values over a 3 year period. Pension expense consists of current service costs and adjustments arising from plan amendments, changes in assumptions, and experience gains or losses which are amortized on a straight-line basis over the expected average remaining service life of the relevant employee group. The costs of health care and life insurance benefits for retirees are expensed as incurred.

Price Risk Management

Certain of the Company's operations engage in price risk management activities to manage exposure to changes in the market prices of natural gas, electric power, interest rates, foreign currency exchange rates and transportation contracts.

The cash flow impact of financial instruments is reflected as cash flows from operating activities in the Consolidated Statements of Cash Flow.

Energy Marketing

Effective January 1, 1999, the Company adopted mark-to-market accounting for the Company's energy marketing operations. This accounting policy change has been applied on a retroactive basis without restatement of prior years.

The impact of the accounting change on retained earnings as at January 1, 1999 is as follows:

($million)	1999
Assets from price risk management activities	
Current	198
Long term	141
Liabilities from price risk management activities	
Current	(188)
Long term	(141)
Unamortized energy contracts (Note 13)	(58)
Other unamortized energy contracts	(3)
Deferred income taxes	15
Retained earnings	(36)

Financial instruments utilized in connection with energy trading activities are accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, forward, future, swap and option contracts are recorded at market value, net of future physical delivery related costs, and are shown as Assets and Liabilities From Price Risk Management Activities on the Consolidated Balance Sheets. Unrealized gains and losses from newly originated contracts, contract restructurings and the impact of price movements are recorded in Operating Revenues in the Consolidated Statements of Operations. Changes in the assets and liabilities from price risk management activities result primarily from changes in the valuation of the portfolio of contracts, maturity and settlement of contracts and newly originated transactions. The market prices used to value these transactions reflect management's best estimate considering various factors including closing exchange and over-the-counter quotations, time value and volatility factors underlying the commitments. The values are adjusted to reflect the potential impact of liquidating the Company's position in an orderly manner over a reasonable period of time under present market conditions.

Non-trading Activities

Derivative and other financial instruments are also utilized in connection with non-trading activities. The Company enters into forward, future, swap and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. Derivatives held for non-trading price risk management activities are not recorded on the Consolidated Balance Sheets. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

Deferred Charges

Costs as required or permitted by the regulators have been deferred to be recovered from future revenues. Certain regulatory deferrals are subject to future decisions by the relevant regulators who will determine the treatment to be given the various items.

Costs incurred for development projects relate to projects which are in progress. The costs of projects that do not develop into viable operations are expensed. Costs related to long term debt are deferred and amortized on a straight-line basis over the life of the respective debt issues.

Goodwill

Goodwill represents the excess cost of an investment over the fair value of the net assets acquired and is amortized on a straight-line basis over a maximum period of 20 years. Goodwill will be written down to net recoverable value if declines in value, considered to be other than temporary, occur based upon expected undiscounted cash flows.

Gain on Sale of Finance Contracts

The Company periodically sells certain of its asset-based finance contracts to securitization vehicles. Securitization transactions are accounted for as sales of finance contracts. These sales are non-recourse to the Company except to the extent of the Company's retained interest in these securitization vehicles. These transactions result in the removal of the finance contracts from the Company's Consolidated Balance Sheets, the recording of assets received and a gain on sale when the significant risks and rewards of ownership are transferred to the purchaser. The assets received are generally cash and a retained interest in the cash flow of the finance contracts sold. Such retained interest is recorded at estimated fair value and may include cash collateral accounts, excess spread assets, and securities backed by the finance contracts sold. Proceeds on sale are computed as the aggregate of the initial cash consideration and the present value of any additional sale proceeds, net of a provision for anticipated credit losses on the securitized finance contracts and the amount of an arm's length servicing fee.

Any gains on sale resulting from securitization transactions are deferred and amortized over the expected life of the securitzed portfolio.

Income is earned on the securitization investments on an accrual basis. The carrying value of this asset is reduced, as required, based on changes in the Company's share of the estimated credit losses and the effects of changes in the payment rate on the securitized finance contracts. The Company continues to manage the securitized finance contracts and recognizes income equal to an arm's length servicing fee over the term of the securitized finance contracts.

Statement of Cash Flow

Effective January 1, 1999, accounting principles generally accepted in Canada require the statement of cash flow to report actual cash flows during the period classified by operating, investing and financing activities. Investing and financing transactions not requiring the use of cash or cash equivalents are excluded from the Statements of Cash Flow. The Company has adopted this new accounting principle beginning January 1, 1999. The comparative Consolidated Financial Statements and Notes to the Consolidated Financial Statements have been restated to conform to the 1999 presentation.

Stock-Based Compensation Plans

The Company has one stock-based compensation plan, which is described in Note 16. No compensation expense is recognized for these plans when the stock options are issued to employees. Any consideration paid by employees on exercise of stock options is credited to share capital. Share appreciation rights exercised are charged to retained earnings.

Comparative Figures

Certain comparative figures have been reclassified to conform to the 1999 presentation.

2. TRANSFER OF RETAIL SERVICES BUSINESS

On January 1, 1999, following the approval of the Ontario Energy Board, Union Gas Limited transferred its net assets relating to the retail services business to UEI Holdings Inc. This related party transaction has been accounted for at the carrying amounts and resulted in a charge to retained earnings of $38 million as at January 1, 1999, consisting of the costs of transfer of $7 million and the recording of previously unrecorded deferred income taxes on assets transferred of $31 million. The unrecorded deferred income taxes arose through the use of the income taxes currently payable method by Union Gas Limited pursuant to regulatory direction.

3. PENSION PLANS

The Company, its subsidiaries and joint ventures have defined benefit pension plans, defined contribution pension plans and retirement arrangements covering substantially all employees. Normal retirement benefits under these plans commence at age 65 and are related to employees' remuneration and years of service.

The pension expense for the year ended December 31, 1999, was $8 million (for the year ended December 31, 1998 – $15 million, for the year ended December 31, 1997 – $17 million).

The pension fund assets at December 31, 1999 are $537 million (December 31, 1998 – $546 million) and the projected pension obligations at December 31, 1999 are $478 million (December 31, 1998 – $538 million). The projected pension obligations represent the discounted value of benefits expected to be paid to plan members, based on projected salaries, rates of return and years of service.

The assumed future rates of return on assets and discount rates used to determine the projected pension obligations of the plans range from 7% to 8% for 1999. The future long term salary and wage escalation rates, including merit increases, range from 3.25% to 6.0% for 1999.

4. LONG TERM DEBT

December 31 ($million)	Due Date	1999	1998
WESTCOAST ENERGY INC.			
Unsecured Debentures			
8.3%–average fixed rate (8.3%–1998)	2000 – 2027	2,155	2,320
CENTRA GAS UTILITIES INC. AND SUBSIDIARIES			
Unsecured Senior Debentures			
9.5%–average fixed rate (9.4%–1998)	2000 – 2025	1,642	1,792
Term Bank Loans and Other			
7.9%–average fixed rate (7.9%–1998)	2000 – 2009	245	330
CENTRA GAS HOLDINGS INC.			
Term Bank Loans			
5.5%–average year end rate (5.7%–1998)	2003	350	350
FOOTHILLS PIPE LINES LTD.			
Term Bank Loans			
6.7%–average year end rate (7.4%–1998)	2003 – 2005	163	169
PACIFIC NORTHERN GAS LTD.			
Secured Debentures			
9.3%–average fixed rate (9.1%–1998)	2002 – 2027	89	92
MARITIMES & NORTHEAST PIPELINE			
Senior Secured Notes			
US$90 million			
7.7%–average year end rate	2019	130	—
Senior Secured Bonds			
6.9%–average fixed rate	2019	98	—
Term Bank Loans			
5.9%–average year end rate	2009	117	—
US$99 million			
6.4%–average year end rate	2009	142	—
CANTARELL NITROGEN PROJECT			
Term Bank Loans			
US$125 million			
6.3%–average year end rate	2008 – 2010	180	—
EMPIRE STATE PIPELINE			
Term Bank Loans			
US$43 million ($48 million–1998)			
5.9%–average year end rate (6.3%–1998)	2009	62	73
WESTCOAST POWER HOLDINGS INC. AND SUBSIDIARIES			
Senior Secured Notes			
9.3%–average fixed rate (9.4%–1998)	2006	22	26
Term Bank Loans and Other			
7.2%–average year end rate (6.7%–1998)	2004 – 2021	477	373
		5,872	5,525
Deduct long term debt due within one year		322	228
		5,550	5,297

Term Bank Loans and Other facilities are collateralized by the entity's assets, key agreements, or ownership interests, or a combination thereof.

Consolidated long term debt repayments, including sinking fund obligations, are:

Due Date	$million	Due Date	$million
2000	322	2005–2009	1,474
2001	204	2010–2014	651
2002	349	2015–2019	977
2003	789	2020–2024	113
2004	398	2025–2029	595
	2,062		3,810

Consolidated interest on long term debt for the year ended December 31, 1999, was $460 million (for the year ended December 31, 1998 – $441 million, for the year ended December 31, 1997 – $426 million).

The debt of joint ventures is non-recourse to the Company. The security provided by each joint venture is limited to the rights and assets of that joint venture and does not extend to the rights and assets of the Company, except to the extent of the Company's investment.

5. BANK INDEBTEDNESS

The Company, its subsidiaries and joint ventures have operating lines of credit in excess of $1,700 million with Canadian chartered banks that enable the Company, its subsidiaries and joint ventures to borrow directly from the banks, to issue bankers' acceptances, and to support commercial paper programs.

The average year end interest rate applicable to the consolidated bank indebtedness at December 31, 1999, was 5.5% (December 31, 1998 – 5.3%).

6. SUPPLEMENTAL CASH FLOW INFORMATION

Non-cash working capital changes

For the years ended December 31 ($million)	1999	1998	1997
Accounts receivable	44	84	(183)
Inventory and prepayments	(67)	(8)	(73)
Accounts payable and accrued liabilities	27	(42)	229
Interest and taxes payable	17	(53)	11
	21	(19)	(16)
Attributable to financing and investing activities	64	(73)	(14)
Attributable to operating activities	(43)	54	(2)

Interest and tax payments

For the years ended December 31 ($million)	1999	1998	1997
Income taxes	43	133	156
Interest	514	514	468

7. INCOME TAXES

A reconciliation between the statutory and the effective rate of income taxes is provided as follows:

For the years ended December 31 ($million)	1999	1998	1997
Income before income taxes and non-controlling interest	323	252	368
Combined Canadian federal and provincial statutory income tax rates, including surtaxes (percent)	45.0	45.0	44.9
Statutory income tax rates applied to accounting income	145	113	165
Increase (decrease) in income taxes resulting from:			
– The use of the income taxes currently payable method applicable to utility operations:			
– Capital cost allowance claimed for income tax purposes in excess of depreciation	(22)	(37)	(47)
– Other items recognized for income tax purposes (in advance of) subsequent to accounting income recognition	(27)	(18)	3
	(49)	(55)	(44)
– Foreign earnings subject to different tax rates	(10)	(4)	(2)
– Utilization of prior years' losses which have not been previously recognized	(25)	(17)	(9)
– Current year's losses for which tax benefits have not been recognized	—	4	6
– Resource allowance deduction	(10)	(11)	(11)
– Large corporation tax in excess of surtax	19	17	14
– Regulatory drawdown of deferred taxes	(9)	—	—
– Other	(15)	1	4
	(99)	(65)	(42)
Provision for income taxes	46	48	123
Effective rate of income taxes (percent)	14.2	19.0	33.4

Income taxes by geographic location were:

For the years ended December 31 ($million)	1999	1998	1997
Income before income taxes and non-controlling interest			
Canada	273	249	364
Foreign	50	3	4
	323	252	368
Current income taxes			
Canada	83	121	156
Foreign	(4)	4	2
	79	125	158
Deferred income taxes			
Canada	(47)	(67)	(31)
Foreign	14	(10)	(4)
	(33)	(77)	(35)
Provision for income taxes	46	48	123

Certain of the Company's utility businesses have been directed by their respective regulators to refund deferred taxes collected in prior years by applying them against future costs in order to reduce tolls. The deferred taxes will be reduced in future years as the timing differences which gave rise to these deferred income taxes reverse, or as amounts are applied to reduce tolls.

With respect to the computation of deferred income taxes, the sources of timing differences and the income tax effects of each were:

For the years ended December 31 ($million)	**1999**	**1998**	**1997**
Depreciation and amortization in excess of capital cost allowance claimed for income tax purposes	(39)	(35)	(20)
Net regulated deferrals included for tax purposes	(2)	(21)	(18)
Net utilization (benefit) of tax losses recognized for accounting purposes	13	(11)	12
Regulatory drawdown of deferred taxes	(9)	—	—
Other items recognized for accounting purposes subsequent to (in advance of) income tax purposes	4	(10)	(9)
Deferred income taxes	(33)	(77)	(35)

If all the companies had used the income tax allocation method for regulated utility operations, the additional provisions for the years ended December 31 and the additional accumulated provisions would be:

For the years ended December 31 ($million)	**1999**	**1998**	**1997**
Unrecorded deferred taxes, beginning of year	704	655	611
Increase in unrecorded deferred taxes	16	49	44
Adjustment on transfer of retail services business (Note 2)	(31)	—	—
Unrecorded deferred taxes, end of year	689	704	655

8. DEFERRED CHARGES AND OTHER ASSETS

December 31 ($million)	**1999**	**1998**
Regulatory	168	153
Development projects (Note 12)	51	30
Debt discount, premium and expense	46	32
Goodwill (Note 11)	22	17
Other	65	49
	352	281

9. EARNINGS AND OPERATING CASH FLOW PER COMMON SHARE

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year.

For the years ended December 31	1999	1998	1997
Net income applicable to common shares ($million)	222	161	210
Number of shares (million)			
Shares outstanding, beginning of year	113	103	101
Changes due to common shares issued, options exercised and shares issued under the Dividend Reinvestment and Share Purchase Plan	1	2	1
Weighted average shares for the year	114	105	102
Earnings per common share — basic	$1.95	$1.53	$2.06

Fully diluted earnings per common share are calculated using an adjusted average number of common shares outstanding during the year and an adjusted net income applicable to common shares, which reflect the potential exercise of share purchase options and the conversion of preferred shares (Notes 14 and 15). An imputed after-tax return of 2.8% has been used in these calculations.

For the year ended December 31	1999
Adjusted net income applicable to common shares ($million)	259
Adjusted weighted average shares for the year (million)	145
Earnings per common share — fully diluted	$1.78

Operating cash flow per common share is also calculated using the weighted average number of common shares outstanding during the year applied to cash flow from operating activities before adjusting for non-cash working capital changes.

For the years ended December 31	1999	1998	1997
Operating cash flow before non-cash working capital changes ($million)	499	448	522
Weighted average shares for the year (million)	114	105	102
Operating cash flow per common share	$4.38	$4.24	$5.10

10. INVESTMENTS IN JOINT VENTURES

The following condensed statements of operations, cash flow and balance sheets detail the Company's share of its investments in joint ventures that have been proportionately consolidated:

For the years ended December 31 ($million)	1999	1998	1997
Proportionate Statements of Joint Venture Operations			
Operating revenues	3,881	4,820	4,367
Operating expenses	(3,763)	(4,762)	(4,296)
Other income	28	11	6
Interest on debt	(62)	(47)	(26)
Income taxes	(4)	(4)	(3)
Net income	80	18	48

For the years ended December 31 ($million)	1999	1998	1997
Proportionate Statements of Joint Venture Cash Flow			
Operating activities	112	91	9
Investing activities	(710)	(363)	(166)
Financing activities	598	311	145
Increase (decrease) in cash and short term investments during the year	—	39	(12)

December 31 ($million)	1999	1998
Proportionate Joint Venture Balance Sheets		
Current assets	610	496
Investments	1	2
Assets from price risk management activities	186	—
Fixed assets	1,872	1,290
Deferred charges and other assets	85	66
	2,754	1,854
Current liabilities	684	437
Liabilities from price risk management activities	154	—
Long term debt	1,233	646
Deferred income taxes	43	43
Westcoast Energy's investment carrying value, including bridge financing	640	728
	2,754	1,854

(a) The Company has a 45% interest in a consortium which has entered into a contract with Pemex Exploración y Producción (PEP) to build, own and operate an offshore gas compression and liquids recovery facility in the Cantarell oil field. The facility will compress natural gas for PEP for processing and ultimate delivery into the Mexican national pipeline system.

The engineering, procurement and construction (EPC) contractor retained for the project has encountered certain construction problems, as a result of which the in-service date for the facility has been delayed. In addition, work activity in early October suffered from the substantial rains and flooding experienced on the east coast of Mexico. Force majeure has been declared for the period during which work was impeded by the floods. In the event that completion is not achieved within the contractual time frame, PEP has the right to cancel the contract. Discussions have been initiated with PEP to obtain an extension to the contract in-service date as a result of the difficulties experienced by the EPC contractor and the force majeure as a result of flooding.

11. ACQUISITIONS

(a) Vector Pipeline Project

During 1999, the Company purchased a 30% equity interest in the Vector Pipeline Project (Vector) from an existing Vector partner for cash of $30 million. The costs of acquiring the Company's interest in Vector exceed the figure at which the equivalent proportion of the net assets is recorded in the books of Vector by $6 million. This excess will be amortized on a straight-line basis over 15 years upon commencement of operations.

(b) Heating, Ventilation and Air Conditioning (HVAC) Businesses

During 1999 and 1998, the Company purchased 100% of the outstanding shares in, or certain assets of, 13 and 15 HVAC businesses, respectively. The acquisitions have been accounted for by the purchase method as follows:

December 31 ($million)	1999	1998
Fixed assets	2	4
Working capital	3	3
Goodwill	5	17
Assumption of long term debt	(1)	(1)
Cash purchase price	9	23

(c) Alliance Pipeline Projects

During 1998, the Company purchased additional interests in the Alliance Pipeline Projects (Alliance) from existing Alliance partners for cash of $88 million (1997 – $8 million). As a result of these transactions, the Company's equity interest in Alliance increased to 23.6% from 10.5%. The costs of acquiring the Company's interests in Alliance exceed the figure at which the equivalent proportion of the net assets is recorded in the books of Alliance by $20 million. This excess will be amortized on a straight-line basis over 25 years upon commencement of operations.

(d) Island Cogeneration Project

During 1998, the Company purchased an additional 60% in the Island Cogeneration Project (ICP) from its partner for cash of $26 million. As a result of this transaction, the Company has a 100% interest in ICP. The costs of acquiring the Company's interest in ICP exceed the figure at which the equivalent proportion of the net assets is recorded in the books of ICP by $21 million. This excess has been allocated to fixed assets and energy contracts.

(e) P.T. Puncakjaya Power

During 1997, the Company purchased additional interests in P.T. Puncakjaya Power, increasing its interest from 20% to 43%, and concurrently refinanced a major expansion of its power facilities. The acquisitions have been accounted for by the purchase method as follows:

December 31 ($million)	1997
Fixed assets	256
Working capital	8
Long term debt	(214)
Deferred charges and other assets	(3)
Cash purchase price	47

12. DISPOSITIONS

(a) In 1999, the Company sold its wholly owned subsidiary Centra Gas Manitoba Inc. for cash of $245 million resulting in a pre-tax gain of $76 million.

(b) In 1999, the Company sold its interest in the Fort Nelson Powerline joint venture for cash of $10 million resulting in a pre-tax gain of $5 million.

(c) In 1999, Westcoast Capital Corporation sold certain of its asset-based finance contracts for proceeds of $77 million, of which $74 million was cash. The proceeds approximated net book value.

(d) In 1998, the Company sold its wholly owned subsidiary Centra Gas Alberta Inc. for cash of $61 million resulting in a pre-tax gain of $20 million.

(e) In 1998, the Company sold its 50% interest in a joint venture to build a natural gas pipeline in Australia for cash of $27 million, resulting in a pre-tax gain of $8 million.

Supplemental information regarding dispositions is as follows:

December 31 ($million)	1999	1998
Cash and short term investments	—	—
Total assets other than cash and short term investments	517	102
Total liabilities	272	50

13. INVESTMENTS

December 31 ($million)	1999	1998
Alliance Pipeline Projects (Note 11)	348	177
Vector Pipeline Project (Note 11)	41	—
Finance contracts (Note 12)	42	124
Energy contracts (a)	—	58
Other	23	15
	454	374

(a) During 1997, the Company and The Coastal Corporation (Coastal) merged their natural gas and electric power marketing businesses. The joint venture businesses operate as Engage Energy Canada, L.P. in Canada and Engage Energy US, L.P. in the United States (combined, Engage Energy).

Each party contributed energy contracts and cash to the joint ventures with an aggregate fair value of approximately $194 million each. In conjunction with this, the Company purchased approximately $65 million of existing contracts from Coastal in order to equalize its ownership in each of the two joint ventures at 50%. This amount was recorded as energy contracts in 1997 and was being amortized on a straight-line basis over 10 years. The unamortized amount of $58 million as at January 1, 1999 was charged to retained earnings upon adoption of mark-to-market accounting for the Company's energy marketing operations (Note 1).

14. PREFERRED STOCK

The Company is authorized to issue an unlimited number of preferred shares, in two classes issuable in series, without nominal or par value. Preferred shares issued for cash and outstanding are:

December 31 ($million)	1999	1998
4,610,237 (1998 – 4,631,407) – 8.08% Cumulative First Preferred Shares, Series 2 (a)(f)	115	116
nil (1998 – 5,000,000) – 6.90% Cumulative Redeemable First Preferred Shares, Series 4 (b)(f)	—	125
8,000,000 – 4.90% Cumulative Redeemable First Preferred Shares, Series 5 (c)(f)	200	200
5,000,000 – 4.72% Cumulative Redeemable First Preferred Shares, Series 6 (c)(f)	125	125
6,000,000 – 5.50% Cumulative First Preferred Shares, Series 7 (d)(f)	150	150
6,000,000 – 5.60% Cumulative First Preferred Shares, Series 8 (e)(f)	150	—
5,000,000 – 5.00% Cumulative Redeemable First Preferred Shares, Series 9 (c)(f)	125	—
	865	716

(a) The Series 2 Preferred Shares are convertible into common shares of the Company at the option of the holder or the Company at the ratio determined by dividing $25.00 by the greater of $1.00 and 95% of a 20 day weighted average trading price of the Company's common shares. In 1999, preferred shareholders exercised their conversion privileges, resulting in the issuance of 18,660 (1998 – 138,334) common shares of the Company (Note 15).

(b) The 6.90% Cumulative Redeemable First Preferred Shares, Series 4, were redeemed by the Company in October 1999 for cash of $125 million plus accrued dividends.

(c) The Series 5, 6 and 9 Preferred Shares are convertible into common shares of the Company, at the option of the holder, on or after January 1, 2002, April 15, 2003, and January 15, 2005, respectively, at the ratio determined by dividing $25.00 together with accrued and unpaid dividends, by the greater of $3.00 and 95% of a 20 day weighted average trading price of the Company's common shares.

The Company has the option to redeem the Series 5, 6 and 9 Preferred Shares on or after October 1, 2001, January 15, 2003 and October 15, 2004, respectively, at $25.00 plus accrued and unpaid dividends or to convert these shares into common shares of the Company, at the ratio determined by dividing $25.00 together with accrued and unpaid dividends, by the greater of $3.00 or 95% of a 20 day weighted average trading price of the Company's common shares.

(d) The Company has the option to redeem the Series 7 Preferred Shares on or after October 15, 2013 at $25.00 per share plus accrued and unpaid dividends.

(e) The Company has the option to redeem the Series 8 Preferred Shares on or after July 15, 2004, at prices ranging from $25.00 to $26.00 per share plus accrued and unpaid dividends.

(f) The issue costs of preferred shares, net of income taxes, have been charged to retained earnings.

15. COMMON STOCK

The Company is authorized to issue an unlimited number of common shares without nominal or par value. Common shares issued and outstanding are:

	shares	$million
• Balance – December 31, 1996	100,747,253	1,354
(a) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from $21.32 to $28.60 per share.	2,178,423	52
(b) Shares issued for cash on options exercised at option prices ranging from $17.69 to $24.02 per share.	320,200	6
• Balance – December 31, 1997	103,245,876	1,412
(a) Shares issued for cash under a public offering at a price of $30.30 per share. The issue costs of these shares, amounting to $9 million, less income taxes of $4 million, have been charged to retained earnings.	7,315,000	222
(b) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from $26.85 to $33.65 per share.	1,701,448	51
(c) Shares issued for cash on options exercised and shares issued under share appreciation rights, at option prices ranging from $17.69 to $24.02 per share.	270,109	6
(d) Shares issued on the conversion of First Preferred Shares, Series 2 (Note 14)	138,334	4
• Balance – December 31, 1998	112,670,767	1,695
(a) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from $25.98 to $30.51 per share.	1,989,110	55
(b) Shares issued for cash on options exercised and shares issued under share appreciation rights, at option prices ranging from $17.69 to $24.02 per share.	168,978	4
(c) Shares issued on the conversion of First Preferred Shares, Series 2 (Note 14)	18,660	1
• Balance – December 31, 1999	114,847,515	1,755

In 1999, the Directors granted 1,351,100 options, at prices ranging from $24.51 to $30.33 per share based on a 10 day weighted average trading price of the Company's common shares on The Toronto Stock Exchange. At December 31, 1999, 4,690,853 common shares were under option at prices ranging from $17.69 to $34.45 per share, of which 2,622,800 are eligible for share appreciation rights that allow the holder to receive 50% of the appreciated value in cash and the balance in common shares of the Company. At December 31, 1999, 428,889 common shares were reserved for issuance upon the exercise of options.

At December 31, 1999, 1,610,070 common shares were reserved for issuance under the Dividend Reinvestment and Share Purchase Plan.

Preferred shares amounting to $20 million held by a non-controlling interest in UEI Holdings Inc. are convertible into common shares of the Company at any time at the option of the holder at 95% of a 20 day weighted average trading price of the Company's common shares on The Toronto Stock Exchange.

16. STOCK-BASED COMPENSATION PLANS

Stock Option Plan

Under the Long Term Incentive Share Option Plan 1989 (the "1989 Plan"), the Company has granted regular key employee retention and performance-based stock options to its employees. Stock options are granted at an exercise price that equals the market price as defined in the 1989 Plan of the Company's shares on the date of grant.

Regular stock options vest in five equal stages with the first stage vesting immediately on the date of the grant and the remainder in four equal annual stages commencing on the first anniversary of the date of grant. Key employee retention stock options commence vesting two years after the date of issuance and then vest in three equal annual instalments. The maximum term of both stock options awarded under the 1989 Plan is ten years. The 1989 Plan also provides for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right.

Performance-based stock options commence vesting when a pre-determined performance threshold has been achieved. The options then vest in three equal annual stages commencing on the date the performance threshold is achieved. The maximum term for performance-based options awarded under the 1989 Plan ranges from five to eight years. Share appreciation rights have not been attached to performance-based options awarded under the 1989 Plan.

A summary of the status of the Company's stock option plan as of December 31, 1999 and 1998, and changes during the years ending on those dates is presented below:

	1999		1998	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at beginning of year	3,631,220	$25.00	2,872,960	$21.22
Granted	1,351,100	$25.70	1,076,300	$34.09
Exercised	(168,978)	$20.87	(270,109)	$21.30
Forfeited	(122,489)	$25.09	(47,931)	$22.40
Outstanding at end of year	4,690,853	$25.36	3,631,220	$25.00
Options exercisable at year-end	1,865,740		1,398,365	

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/99	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/99	Weighted-Average Exercise Price
$17-22	1,909,653	4.1	$20.68	1,464,114	$20.72
$24-25	1,381,100	9.2	$24.36	232,606	$24.02
$28-31	367,100	9.0	$28.88	69,420	$28.80
$33-35	1,033,000	4.5	$34.08	99,600	$34.45
$17-35	4,690,853			1,865,740	

17. FINANCIAL INSTRUMENTS

Energy Marketing

Engage Energy engages in the marketing and trading of natural gas and electric power and executes financial derivatives related to these commodities for overall management of its contractual portfolio and physical positions. Engage Energy's portfolio of natural gas and electric power contracts is comprised primarily of forward, future, swap and option contracts for periods of up to 15 years, which also include related fixed and floating price commitments. These transactions give rise to certain business risks, including market and credit risk. Engage Energy uses a variety of derivative instruments to manage these risks.

Market Risk

Market risk is the risk that the value of the portfolio will change, either favourably or unfavourably, in response to changing market conditions. Market risks are monitored by an internal risk management group independent of Engage Energy's trading activities to ensure compliance to Company standards. The Company monitors and manages its exposure to market risk through a variety of risk management techniques. Such procedures include measurement of risk, market comparisons, monitoring of all commitments and positions, and daily reporting to senior management. In addition, sensitivity to changes in market price and market volatility are examined on a daily basis.

Credit Risk

In connection with the market valuation of its energy trading contracts, Engage Energy maintains certain reserves for a number of risks and costs associated with these future commitments. Among others, these include reserves for credit risks based on the financial condition of counterparties, reserves for product location differentials and consideration of the time value of money for long-term contracts. Credit risk is the risk of loss from non-performance by suppliers, customers or financial counterparties to a contract. Engage Energy's operations are primarily concentrated in the natural gas and electric power industries and major customers' operations are also heavily concentrated in the same industries. Engage Energy maintains credit policies with respect to all its counterparties, which management believes significantly minimizes overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure, monitoring of aggregate exposure against limits by the internal credit risk management group and the use of standardized agreements which allow for the netting of positive and negative exposures associated with a single counterparty. The credit risk management group reviews and monitors the application of these policies for suppliers, customers and counterparties. Customers not meeting minimum standards must provide secured credit terms. The counterparties associated with assets from price risk management activities net of reserves as of December 31, 1999, are summarized as follows:

December 31 ($million)	1999	
	Investment Grade (a)	**Total**
Gas and electric utilities	63	64
Energy marketers	39	41
Financial institutions	51	51
Independent power producers	41	41
Oil and gas producers	37	62
Industrials	3	8
Pipelines and other	30	30
Total	264	
Assets from price risk management activities (b)		297

(a) "Investment Grade" is primarily determined using publicly available credit ratings along with consideration of collateral, which encompass letters of credit, parent company guarantees and property interests, including oil and gas reserves. Included in "Investment Grade" are counterparties with a minimum Standard & Poor's or Dominion Bond Rating Service rating of BBB- or Moody's rating of Baa3, respectively, or minimum implied (through internal financial credit analysis) Standard & Poor's equivalent rating of BBB-.
(b) Two customers' exposures at December 31, 1999, comprise greater than 5% of Assets From Price Management Activities. All are included above as Investment Grade.

In late June 1998, unusual and prolonged hot weather combined with forced electrical outages lead to electricity spikes that resulted in two of Engage Energy's customers defaulting on their obligations to deliver electricity. To meet its own sales commitments, Engage Energy was required to purchase replacement electricity in the market at substantially higher prices, resulting in a pre-tax loss, of which the Company's proportionate share was $21 million.

Natural Gas

The natural gas supply of the Company's Gas Distribution businesses includes gas supply contracts with pricing mechanisms that vary with gas price indices, rather than fixed prices. For some of these contracts, the effective purchase price has been fixed through the use of gas price swap contracts. The differences between the price of natural gas used for toll purposes and the effective cost of gas purchased is deferred for future disposition as approved by the respective regulators. The difference, if any, between amounts actually recorded as receivable or payable at year end and amounts actually approved for recovery by the regulator is charged to income at the time of the regulator's decision. The net payable position of these deferrals at December 31, 1999, was approximately $65 million (December 31, 1998 – $3 million).

In 1998, the Manitoba Public Utilities Board approved the recovery of $19 million and disallowed the recovery of $27 million of a total of approximately $46 million of natural gas costs related to price management activities which were deferred at December 31, 1997. Of the total $27 million of disallowed natural gas costs, $9 million has been recovered from brokers serving the direct purchase market.

Approximately 55% of the forecast 2000 gas supply of the Gas Distribution businesses from January through December 2000, is indexed to variable pricing mechanisms. At December 31, 1999, the purchase price applicable to 18 billion cubic feet (Bcf) or 20% of this indexed supply has been effectively fixed through the use of natural gas swaps and other contracts.

Notional Amounts of Derivative Instruments

The approximate notional amount of natural gas derivative instruments at December 31, 1999 is 2,171,624 Bcf (December 31, 1998 – 1,859,018 Bcf) with a maximum 10 years in term.

Notional amounts reflect the volume of transactions but do not represent the amounts exchanged by the parties to the financial instruments. Accordingly, notional amounts do not accurately measure the Company's exposure to market or credit risks. The maximum terms in years detailed above are not indicative of likely future cash flows as these instruments may be traded in the markets at any time in response to the Company's risk management needs.

Interest Rate Swaps

The Company uses interest rate swaps to manage the fixed and floating interest rate mix of the total debt portfolio. By entering into interest rate swap agreements, the Company agrees to exchange with the Canadian chartered banks the difference between the fixed rate and floating rate interest payments calculated by reference to bankers' acceptances rates and on an agreed notional amount. The notional amount does not represent the amount exchanged by the counterparties, and therefore is not a measure of market or credit exposure. The Company or its subsidiaries have entered into floating to fixed rate swap agreements on $555 million with an average pay rate of 7.1% and an average maturity date of approximately 5 years.

Foreign Currency Contracts

The Company purchases and sells energy commodities in United States dollars. To reduce risk and protect margins when purchase and sale contracts are denominated in United States dollars, the Company enters into forward foreign exchange contracts which establish the foreign exchange rate for the cash flows from these purchase and sale transactions. At December 31, 1999, foreign currency contracts with a notional principal amount of $338 million were outstanding. Such contracts will expire in the period 2000 through 2008.

In order to fix certain construction contracts, the Company entered into forward contracts to purchase Swiss francs and sell United States dollars. At December 31, 1999, Swiss franc contracts with a notional amount of $48 million were outstanding, maturing through to February 2001.

Fair Market Values

The following fair market value (FMV) information is provided solely to comply with financial instrument disclosure requirements. The Company cautions readers in the interpretation of the impact of these estimated fair market values due to the regulated nature of some of the Company's operations. Based on the current regulatory process, any gains or losses arising from the use of financial instruments as approved by respective regulators would be deferred for future disposition by the regulators.

Fair market values have been estimated by reference to quoted market prices for the actual or similar instruments where available. The fair market values of accounts receivable and current liabilities approximate carrying values. The carrying values and approximate fair market values of the Company's financial instruments, excluding energy trading activities which are marked to market, are:

December 31 ($million)	**1999**		**1998**	
	Carrying Value	**Approx FMV**	**Carrying Value**	**Approx FMV**
ASSETS				
Investments	454	452	374	375
Natural gas	—	—	—	166
Foreign currency contracts	—	3	—	2
LIABILITIES				
Long term debt	5,872	6,134	5,525	6,291
Natural gas	—	6	—	305
Interest rate swaps	—	12	—	27

18. FIXED ASSETS

December 31 ($million)	1999	1998
PLANT, PROPERTY AND EQUIPMENT		
Transmission & Field Services		
Natural gas pipeline systems	3,255	2,651
Processing plants	1,290	1,236
Other	192	199
Construction work in progress	57	203
	4,794	4,289
Gas Distribution		
Natural gas pipeline and distribution systems	4,349	4,578
Natural gas storage	551	527
Other	393	982
Construction work in progress	38	41
	5,331	6,128
Power Generation		
Power generation plants	292	283
Other	1	9
Construction work in progress	182	35
	475	327
International		
Power generation plant and other	365	379
Construction work in progress	398	203
	763	582
Services and Other		
Rental assets and other (a)	733	149
	12,096	11,475
ACCUMULATED DEPRECIATION		
Transmission & Field Services	1,260	1,176
Gas Distribution	1,423	1,612
Power Generation	111	92
International	29	12
Services and Other	165	14
	2,988	2,906
	9,108	8,569

(a) Rental assets and other includes the depreciated cost of a customer billing system of $64 million. In accordance with current accounting standards, management uses estimated expected future net cash flows to measure the recoverability of its investment in the customer billing system. The estimation of expected future net cash flows is inherently uncertain and relies to a considerable extent on assumptions regarding current and future economic and market conditions. If, in future periods, there are changes in the estimates or assumptions incorporated into the impairment review analysis, the changes could result in an adjustment to the carrying amount of the customer billing system.

19. SEGMENTED INFORMATION

The operating segments presented are those adopted by senior management based on the Company's internal reporting system.

The operations of the Company have been grouped according to the following business segments:
Transmission & Field Services — natural gas gathering, processing and transmission;
Gas Distribution — natural gas distribution and storage and transmission;
Power Generation — electrical and thermal energy generated from natural gas;
International — international operations;
Services — energy marketing, retail energy services and information technology and financial services;
Other — other activities, including corporate expenses, business development expenditures, corporate financing expenses and utilization of previous years' unrecorded tax losses.

Inter segment revenues are earned in the normal course of operations and are recorded at amounts established and agreed upon between the operating segments.

The Company has international businesses and development projects which are primarily located in the United States, Mexico, Indonesia and China. The percentages of the Company's consolidated operating revenues net of cost of sales, consolidated operating income and consolidated fixed assets and goodwill represented by these businesses and development projects are:

For the years ended December 31 ($million)	1999	1998	1997
Operating revenues, net of cost of sales	5%	4%	3%
Operating income	13%	2%	2%
Fixed assets and goodwill	14%	13%	

Statements of segmented operations for the years ended December 31 are as follows:

($million, except for share data) 1999	Transmission & Field Services	Gas Distribution	Power Generation	International	Services	Other	Total
Total revenues	722	1,876	119	68	3,890	2	6,677
Inter segment revenues	(5)	(7)	—	—	(400)	—	(412)
Operating revenues	717	1,869	119	68	3,490	2	6,265
Depreciation	(123)	(183)	(19)	(18)	(56)	(2)	(401)
Other operating expenses	(292)	(1,331)	(91)	(12)	(3,484)	(31)	(5,241)
Operating income (loss)	302	355	9	38	(50)	(31)	623
Interest income	2	1	1	2	3	46	55
Interest expense	(172)	(208)	(6)	(21)	(9)	(83)	(499)
Other items	45	83	7	1	1	7	144
Income (loss) before undernoted items	177	231	11	20	(55)	(61)	323
Income taxes	(22)	(68)	—	(5)	23	26	(46)
Non-controlling interest	—	(9)	—	—	—	(1)	(10)
Net income (loss)	155	154	11	15	(32)	(36)	267
Provision for preferred dividends	(1)	—	—	—	—	(44)	(45)
Net income (loss) applicable to common shares	154	154	11	15	(32)	(80)	222
Per common share — basic	$1.35	$1.35	$0.10	$0.13	$(0.28)	$(0.70)	$1.95
Operating cash flow	238	246	25	38	14	(62)	499
Operating cash flow per common share	$2.09	$2.16	$0.22	$0.33	$0.12	$(0.54)	$4.38
Additions to fixed assets and goodwill	555	292	183	217	105	(35)	1,317
Total assets	4,184	4,608	421	769	1,542	253	11,777

($million, except for share data) 1998	Transmission & Field Services	Gas Distribution	Power Generation	International	Services	Other	Total
Total revenues	680	2,073	95	48	4,711	5	7,612
Inter segment revenues	(8)	(3)	—	—	(225)	—	(236)
Operating revenues	672	2,070	95	48	4,486	5	7,376
Depreciation	(109)	(212)	(15)	(12)	(16)	—	(364)
Other operating expenses	(278)	(1,439)	(62)	(2)	(4,538)	(43)	(6,362)
Operating income (loss)	285	419	18	34	(68)	(38)	650
Interest income	—	4	1	2	5	7	19
Equity income	4	—	—	—	—	—	4
Interest expense	(157)	(227)	(7)	(24)	(6)	(67)	(488)
Other items	14	21	—	8	—	24	67
Income (loss) before undernoted items	146	217	12	20	(69)	(74)	252
Income taxes	(16)	(90)	(6)	(4)	23	45	(48)
Non-controlling interest	—	(5)	—	—	—	(1)	(6)
Net income (loss)	130	122	6	16	(46)	(30)	198
Provision for preferred dividends	(2)	—	—	—	—	(35)	(37)
Net income (loss) applicable to common shares	128	122	6	16	(46)	(65)	161
Per common share — basic	$1.22	$1.16	$0.06	$0.15	$(0.44)	$(0.62)	$1.53
Operating cash flow	234	283	25	30	(65)	(59)	448
Operating cash flow per common share	$2.22	$2.68	$0.24	$0.28	$(0.62)	$(0.56)	$4.24
Additions to fixed assets and goodwill	272	339	7	180	105	1	904
Total assets	3,555	5,464	278	402	792	329	10,820

($million, except for share data) 1997	Transmission & Field Services	Gas Distribution	Power Generation	International	Services	Other	Total
Total revenues	639	2,405	113	12	4,228	4	7,401
Inter segment revenues	—	(11)	(4)	—	(74)	—	(89)
Operating revenues	639	2,394	109	12	4,154	4	7,312
Depreciation	(97)	(202)	(18)	(1)	(11)	—	(329)
Other operating expenses	(254)	(1,679)	(68)	—	(4,165)	(24)	(6,190)
Operating income (loss)	288	513	23	11	(22)	(20)	793
Interest income	1	9	1	—	7	3	21
Interest expense	(159)	(236)	(8)	(4)	(5)	(42)	(454)
Other items	8	4	(1)	—	(2)	(1)	8
Income (loss) before undernoted items	138	290	15	7	(22)	(60)	368
Income taxes	(22)	(123)	(4)	(2)	7	21	(123)
Non-controlling interest	—	(6)	—	—	—	(1)	(7)
Net income (loss)	116	161	11	5	(15)	(40)	238
Provision for preferred dividends	(2)	—	—	—	—	(26)	(28)
Net income (loss) applicable to common shares	114	161	11	5	(15)	(66)	210
Per common share — basic	$1.12	$1.58	$0.11	$0.05	$(0.15)	$(0.65)	$2.06
Operating cash flow	195	328	31	2	3	(37)	522
Operating cash flow per common share	$1.90	$3.21	$0.30	$0.02	$0.03	$(0.36)	$5.10
Additions to fixed assets and goodwill	266	380	9	15	4	2	676

20. RECONCILIATION OF GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company prepares its accounts in accordance with accounting principles generally accepted in Canada (Canadian GAAP) which in the main, parallel accounting principles generally accepted in the United States (US GAAP). The following reconciliations reflect the major differences in accounting principles.

Consolidated net income under US GAAP would be:

For the years ended December 31 ($million, except for share data)	1999	1998	1997
Net income under Canadian GAAP	267	198	238
Adjustments			
Post-retirement benefits other than pensions (a)	(4)	(4)	(5)
Income taxes (b)	—	1	(3)
Costs of start-up activities (c)	(45)	—	—
Initial adoption of mark-to-market accounting (f)	(36)	—	—
Other (d)(e)(h)	(5)	(3)	(1)
Net income under US GAAP	177	192	229
Provision for dividends on preferred shares (h)	45	37	28
Net income under US GAAP applicable to common shares	132	155	201
Common shares — weighted average (million)	114	105	102
Earnings per common share under US GAAP — basic	$1.16	$1.47	$1.97
— fully diluted	$1.15		

Consolidated comprehensive income under US GAAP would be:

For the years ended December 31 ($million)	1999	1998	1997
Net income under US GAAP applicable to common shares	132	155	201
Change in the Cumulative Translation Adjustment	(31)	9	21
Comprehensive income under US GAAP	101	164	222

Consolidated balance sheet items under US GAAP would be:

December 31 ($million)	1999	1998
ASSETS		
Fixed assets (b)	9,395	8,895
Deferred income taxes (b)	113	65
Deferred charges and other assets (a)(b)(c)(d)	1,609	1,665
LIABILITIES		
Current liabilities (b)(h)	2,294	1,925
Long term debt (h)	5,545	5,292
Long term obligations (a)	62	65
Deferred income taxes (a)(b)(d)	1,989	2,070
Non-controlling interest — preferred shares (h)	135	134
Additional paid in capital (e)	4	—
RETAINED EARNINGS	575	633

(a) The Statement of Financial Accounting Standards (SFAS) 106, Employers' Accounting for Post-Retirement Benefits Other Than Pensions, requires the accrual of liabilities applicable to post-retirement other than pension benefits. The consolidated accumulated post-retirement benefits at December 31, 1999 amount to $62 million (December 31, 1998 – $65 million). The accrual related to the period prior to the introduction of SFAS 106 is being amortized on a straight-line basis over 20 years. Under Canadian GAAP, the costs of health care and life insurance benefits for retirees are expensed as incurred.

(b) SFAS 109, Accounting for Income Taxes, requires deferred income tax balances to be adjusted to reflect current legislated tax rates. For utility operations using the income taxes currently payable method, SFAS 109 requires the recording of deferred income taxes and the corresponding deferred charges which are to be collected from regulated customers in future years.

The variances in deferred income taxes are:

December 31 ($million)	1999	1998
Deferred income taxes under Canadian GAAP	333	340
SFAS 109 utility deferred income taxes	1,383	1,410
Deferred income taxes on excess purchase price amounts	289	329
Other adjustments	(16)	(9)
Total future income tax liability under US GAAP	1,989	2,070

For business acquisitions, the purchase price allocations reflect the recording of additional deferred income tax liabilities on the excess of the purchase prices over the net book values of assets acquired and liabilities assumed. A corresponding increase to fixed assets acquired is also recorded.

(c) Effective January 1, 1999 the Statement of Position (SOP) 98-5, Reporting on the Costs of Start-Up Activities, requires that all costs of start-up activities be expensed as incurred rather than deferred and amortized to income over time as permitted under Canadian GAAP. The cumulative effect of the accounting change of $23 million is included in the determination of net income under US GAAP.

(d) SFAS 87, Employers' Accounting for Pensions, requires that pension fund assets be measured at current market values rather than at average market related values under Canadian GAAP and that the present value of the accrued pension plan obligations be discounted using current interest rates which may be different from management's long term assumptions for interest rates under Canadian GAAP. Using the requirements of SFAS 87, the consolidated pension fund assets at December 31, 1999, would be $537 million and the consolidated pension obligations at December 31, 1999 would be $509 million, and the pension expense would be $14 million for the year ended December 31, 1999 (for the year ended December 31, 1998 – $21 million, for the year ended December 31, 1997 – $19 million).

(e) Effective January 1, 1996, the Company adopted SFAS 123, Accounting for Stock-Based Compensation, which requires that the fair market value of benefits related to stock-based compensation be charged to income over the applicable vesting period under US GAAP rather than as a capital transaction under Canadian GAAP. The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for stock options granted in 1999, 1998 and 1997, respectively: expected dividend yields of 5.0%, 3.6% and 5.0%, expected volatility of 12.9%, 12.5% and 11.1%, risk free interest rate of 6.0%, 4.8% and 5.3% and expected life of 10 years for all grants.

(f) Effective January 1, 1999, the Company adopted mark-to-market accounting for the Company's energy marketing operations. The cumulative effect of a change in accounting principle under US GAAP is included in the determination of net income. Under Canadian GAAP, the cumulative effect is recorded as a charge to retained earnings.

(g) Canadian GAAP require the proportionate consolidation of the Company's investments in joint ventures. The Securities and Exchange Commission regulations permit the filing of financial statements using proportionate consolidation provided that condensed statements of operations, cash flow and balance sheets detailing the Company's share of its investments in joint ventures are provided (Note 10).

(h) Canadian GAAP require debt-like preferred shares and their dividends to be treated as long term debt and interest expense respectively. Under US GAAP, these shares are to be recorded as equity.

20. RECONCILIATION OF GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (continued)

(i) SFAS 133, Derivative Instruments and Hedging Activities, was issued in 1998. This statement, which pursuant to SFAS 137 is effective for the Company January 1, 2001, requires that all derivatives be recorded on the balance sheet at fair value. The Company has not yet calculated the impact that the adoption of this new standard will have on its financial position and results of operations for US GAAP purposes.

21. CUMULATIVE TRANSLATION ADJUSTMENT

The cumulative translation adjustment balance represents the net unrealized foreign currency translation gain on the Company's net investment in self-sustaining foreign businesses. The decrease over the prior year is primarily due to the increase in the Canadian dollar relative to the functional currency of the self-sustaining foreign businesses, principally United States dollars.

22. CONTINGENCIES

(a) Due to the size, complexity and nature of the Company's operations, various legal matters are pending. In the opinion of management, these matters will not have a material effect on the Company's consolidated financial position or results of operations.

(b) The Year 2000 issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The Company, its subsidiaries and joint ventures have made the transition to the year 2000 without incident. The Company is continuing to monitor its systems for date related issues. Although the change in date has occurred and no evidence of any issues has been detected, it is not possible to conclude that all aspects of the Year 2000 issue that may affect the entity, including those related to customers, suppliers, or other third parties, have been fully resolved.

Consolidated Quarterly Results

Unaudited

($million, except for share data)	For the three months ended				
1999	March 31	June 30	Sept. 30	Dec. 31	Total
Operating revenues	1,782	1,478	1,330	1,675	6,265
Operating expenses	1,489	1,376	1,264	1,513	5,642
Operating income	293	102	66	162	623
Other net expenses	96	99	19	96	310
Income taxes	64	(14)	(15)	11	46
Net income	133	17	62	55	267
Provision for dividends on preferred shares	10	11	13	11	45
Net income applicable to common shares	123	6	49	44	222
Earnings per common share — basic	$1.08	$0.05	$0.44	$0.38	$1.95

($million, except for share data)	For the three months ended				
1998	March 31	June 30	Sept. 30	Dec. 31	Total
Operating revenues	2,002	1,664	1,843	1,867	7,376
Operating expenses	1,705	1,589	1,752	1,680	6,726
Operating income	297	75	91	187	650
Other net expenses	119	87	109	89	404
Income taxes	67	(22)	(21)	24	48
Net income	111	10	3	74	198
Provision for dividends on preferred shares	8	9	9	11	37
Net income (loss) applicable to common shares	103	1	(6)	63	161
Earnings per common share — basic	$0.99	$0.01	$(0.06)	$0.59	$1.53

The Company's natural gas distribution businesses are highly seasonal, with the majority of gas deliveries occurring during the winter heating season from mid-October to mid-April. Gas sales during this period typically account for approximately two-thirds of annual gas distribution revenues, resulting in strong first quarter results, second and third quarters that show either small profits or losses, and strong fourth quarter results.

The earnings contribution of the Company's natural gas distribution businesses are also subject to weather variances. Excluding the positive and negative impact of weather, earnings per common share for the Company were $2.10 in 1999 compared with $1.90 in 1998.

For the three months ended (dollar / share)	March 31	June 30	Sept. 30	Dec. 31	Total
1999					
Net income per common share	$1.08	$0.05	$0.44	$0.38	$1.95
Weather impact — gas distribution	$0.05	$0.05	—	$0.05	$0.15
Weather normalized net income per common share	$1.13	$0.10	$0.44	$0.43	$2.10

For the three months ended (dollar / share)	March 31	June 30	Sept. 30	Dec. 31	Total
1998					
Net income (loss) per common share	$0.99	$0.01	$(0.06)	$0.59	$1.53
Weather impact — gas distribution	$0.19	$0.07	$(0.01)	$0.12	$0.37
Weather normalized net income (loss) per common share	$1.18	$0.08	$(0.07)	$0.71	$1.90

Ten-Year Review

Unaudited

	1999	1998	1997
FINANCIAL			
OPERATIONS ($million)			
Operating revenues	6,265	7,376	7,312
Operating expenses	5,642	6,726	6,519
Operating income	623	650	793
Other net expenses	310	404	432
Income taxes	46	48	123
Net income from continuing operations	267	198	238
Discontinued operations	—	—	—
Net income (loss)	267	198	238
Provision for dividends on preferred shares	45	37	28
Net income (loss) applicable to common shares	222	161	210
Dividends on common shares	146	133	122
Operating cash flow			
— From continuing operations	499	448	522
— After discontinued operations	499	448	522
PER COMMON SHARE (dollars)			
Net income (loss)—basic			
— From continuing operations	$1.95	$1.53	$2.06
— After discontinued operations	$1.95	$1.53	$2.06
Operating cash flow			
— From continuing operations	$4.38	$4.24	$5.10
— After discontinued operations	$4.38	$4.24	$5.10
Dividends	$1.28	$1.26	$1.20
ASSETS ($million)			
Fixed assets	9,108	8,569	8,025
Investments	454	374	195
Assets from price risk management activities	186	—	—
Current assets	1,677	1,596	1,574
Deferred charges and other assets	352	281	281
Total assets	11,777	10,820	10,075
CAPITALIZATION ($million)			
Long term debt	5,550	5,297	4,941
Liabilities from price risk management activities	175	—	—
Preferred shareholders' equity	865	716	570
Common shareholders' equity	2,395	2,368	2,056
Deferred income taxes	333	340	400
Current liabilities	2,293	1,935	2,045
Non-controlling interest in subsidiary companies	166	164	63
Total equity and liabilities	11,777	10,820	10,075

1996	1995	1994	1993	1992	1991	1990
4,875	4,184	3,827	3,674	1,818	1,501	1,494
4,088	3,445	3,208	3,107	1,473	1,236	1,240
787	739	619	567	345	265	254
460	436	360	353	224	177	170
115	109	95	68	36	15	22
212	194	164	146	85	73	62
—	—	—	—	(161)	10	21
212	194	164	146	(76)	83	83
19	18	13	13	11	6	6
193	176	151	133	(87)	77	77
105	81	76	65	49	45	44
543	384	342	363	233	189	161
543	384	342	385	292	249	239
$1.96	$2.01	$1.76	$1.70	$1.23	$1.18	$1.03
$1.96	$2.01	$1.76	$1.70	$(1.45)	$1.36	$1.41
$5.50	$4.41	$3.98	$4.64	$3.88	$3.33	$2.93
$5.50	$4.41	$3.98	$4.91	$4.87	$4.39	$4.35
$1.05	$0.93	$0.89	$0.82	$0.80	$0.80	$0.80
7,304	7,056	6,390	5,674	5,678	3,535	3,129
184	162	100	32	87	23	111
—	—	—	—	—	—	—
1,328	994	974	939	844	364	376
250	239	182	145	118	102	103
9,066	8,451	7,646	6,790	6,727	4,024	3,719
4,743	4,715	3,647	3,383	3,396	1,780	1,701
—	—	—	—	—	—	—
445	245	245	120	195	75	75
1,890	1,542	1,417	1,320	1,005	896	850
366	396	399	391	593	368	352
1,517	1,441	1,828	1,465	1,400	827	663
105	112	110	111	138	78	78
9,066	8,451	7,646	6,790	6,727	4,024	3,719

Ten-Year Review

Unaudited

	1999	1998	1997
STATISTICAL			
VOLUMES (Bcf)			
British Columbia Pipeline Division	670	688	688
Foothills Pipe Lines	1,131	940	935
Empire State Pipeline	105	93	98
Union Gas*	1,222	1,127	1,193
Other Gas Distribution#	122	139	163
	3,250	2,987	3,077
RATE BASE ($million)			
British Columbia Pipeline and Field Services Divisions	2,294	2,287	2,273
Foothills Pipe Lines (proportionate share – Phase I – 27%)	224	185	189
Empire State Pipeline (proportionate share – 50%)	120	131	129
Union Gas* ^	2,733	3,206	3,043
Other Gas Distribution#	591	851	937
	5,962	6,660	6,571
NUMBER OF CUSTOMERS (thousand)			
Union Gas*	1,104	1,075	1,041
Other Gas Distribution#	107	344	387
	1,211	1,419	1,428
COMMON SHARES			
Shares outstanding at year-end	114,847,515	112,670,767	103,245,876
Toronto Stock Exchange price ranges			
— high	$31.60	$36.35	$33.50
— low	$22.40	$27.25	$22.65
Number of common shareholders at year-end	8,556	8,645	8,753
Employees at year-end (consolidated – excluding joint ventures)	5,648	6,300	5,932

* amalgamated with Centra Gas Ontario Inc. on January 1, 1998.

^ transferred approximately $500 million of net assets to Westcoast Capital Corporation on January 1, 1999.

\# includes Centra Gas Manitoba and Centra Gas Alberta until sold in 1999 and 1998, respectively.

1996	1995	1994	1993	1992	1991	1990
667	647	605	579	512	465	401
927	920	852	615	534	457	425
101	114	43	6	—	—	—
1,137	1,166	1,034	991	317	127	121
169	165	160	156	147	139	127
3,001	3,012	2,694	2,347	1,510	1,188	1,074
2,114	1,807	1,353	1,236	1,142	914	831
193	193	192	169	157	156	149
130	89	92	88	—	—	—
2,830	2,718	2,496	2,304	2,115	489	455
888	989	937	899	837	763	499
6,155	5,796	5,070	4,696	4,251	2,322	1,934
1,002	965	932	892	852	190	183
372	358	347	332	318	307	305
1,374	1,323	1,279	1,224	1,170	497	488
100,747,253	87,972,872	86,444,582	85,318,602	72,678,965	57,255,169	56,487,209
$24.40	$22.75	$24.63	$22.63	$21.13	$21.50	$22.25
$20.00	$19.25	$19.63	$16.25	$15.00	$19.00	$19.63
8,499	8,447	8,782	8,602	7,828	6,043	6,409
5,991	6,380	6,258	6,043	6,257	3,351	3,331

Directors

William C. Brown was formerly President and CEO of BC Sugar Refinery, Limited, and is a Director of Duke Seabridge Limited and TimberWest Forest Corp. Mr. Brown was first elected to the Board in 1995 and is a member of the Audit and the Human Resources and Compensation Committees.

R. Donald Fullerton is a Director of the Canadian Imperial Bank of Commerce, George Weston Limited, Hollinger Inc., Asia Satellite Telecommunications Company Limited, Orange, plc, and is an Advisory Board Member of IBM Canada Limited. Mr. Fullerton was first elected to the Board in 1993 and is a member of the Audit Committee.

Lorna R. Marsden is President and Vice-Chancellor of York University, and is a Director of Manulife Financial and Gore Mutual Insurance Co. Dr. Marsden was first elected to the Board in 1995 and is a member of the Audit and the Human Resources and Compensation Committees.

George L. Mazanec was formerly Vice Chairman of PanEnergy Corp. (now part of Duke Energy Corporation), and is a Director of National Fuel Gas Company, Aegis Insurance Services, Inc. and Northern Trust Bank of Texas. Mr. Mazanec was first elected to the Board in 1998 and is a member of the Audit Committee.

Marnie Paikin is a Director of Atomic Energy of Canada Limited and Union Gas Limited, and is a Commissioner of the Ontario Human Rights Commission. Ms. Paikin was first elected to the Board in 1993. She is Chair of the Environment, Health and Safety Committee and is a member of the Corporate Governance Committee.

Daniel U. Pekarsky is President of The Corporate Advisory Group Inc., consultants in financial and strategic planning, and is a Director of Search Energy Corp. Mr. Pekarsky was first elected to the Board in 1993. He is Chair of the Executive Committee and is a member of the Corporate Governance and the Human Resources and Compensation Committees.

William G. Saywell is Vice Chairman of Intercedent Ltd., a business development and management consulting firm, and is a Director of the Bank of Tokyo-Mitsubishi (Canada) and Western Garnet International Ltd. Dr. Saywell was first elected to the Board in 1992 and is a member of the Corporate Governance and the Environment, Health and Safety Committees.

Arthur H. Willms was formerly President and COO of Westcoast Energy, and is Chairman and a Director of Union Gas Limited, Pacific Northern Gas Ltd., and Centra Gas British Columbia Inc., and is a Director of Crestar Energy Inc. Mr. Willms was first elected to the Board in 1983 and is a member of the Environment, Health and Safety and the Executive Committees.

Wilbert H. Hopper was formerly Chairman and CEO of Petro-Canada, and served as Chairman of the Board of Westcoast Energy from 1983 to 1992. Mr. Hopper was first elected to the Board in 1979. He is Chair of the Audit Committee and is a member of the Executive Committee.

William H. Neville is Chairman of The Strategies Group, consultants in business, public affairs, government relations, strategic planning and public policy. Mr. Neville was first elected to the Board in 1988. He is Chair of the Corporate Governance Committee and is a member of the Environment, Health and Safety Committee.

Michael E.J. Phelps is Chairman and CEO of Westcoast Energy. Mr. Phelps is a Director of Canfor Corporation, the Canadian Imperial Bank of Commerce and Canadian Pacific Limited. He was appointed President and CEO in 1988, and became Chairman in 1992. Mr. Phelps was first elected to the Board in 1987 and is a member of the Executive Committee.

W. Robert Wyman is Chairman and a Director of Suncor Energy Inc., and is a Director of Finning International Inc. Mr. Wyman was first elected to the Board in 1993. He is Chair of the Human Resources and Compensation Committee and is a member of the Environment, Health and Safety and the Executive Committees.

Edwin C. Phillips *is Director Emeritus of Westcoast Energy. Mr. Phillips, who was CEO of Westcoast Energy from 1975 to 1983, served as a Company Director from 1969 to 1989.*

James S. Palmer Q.C. *retired from the Board effective October 1, 1999. Mr. Palmer was first elected to the Board in 1990.*

Senior Officer and Management Group

CORPORATE

Michael E.J. Phelps
Chairman and Chief Executive Officer

Graham M. Wilson
Executive Vice President and Chief Financial Officer

Kenneth E. Rekrutiak
Senior Vice President

David G. Unruh
Senior Vice President, Law and Corporate Secretary

Eric L. Schwitzer
Senior Vice President, Strategic Development

Bohdan I. Bodnar
Vice President, Human Resources and Administration

Robert R. Foulkes
Vice President, Corporate Communications

TRANSMISSION & FIELD SERVICES

Irvine J. Koop
Executive Vice President
President and Chief Executive Officer, Pipelines and Midstream

Phillip R. Knoll
President, Westcoast Gas Services Inc.

Douglas J. Haughey
President, Westcoast Energy Pipelines and Field Services Division

GAS DISTRIBUTION

Robert T. Reid
Executive Vice President
President and Chief Executive Officer, Union Gas Limited

Jac W. Kreul
President and Chief Executive Officer, Centra Gas British Columbia Inc.

Roy G. Dyce
President and Chief Executive Officer, Pacific Northern Gas Ltd.

POWER GENERATION AND INTERNATIONAL

D. Michael G. Stewart
Executive Vice President, Business Development
President, Westcoast Energy International Inc.

Jeffry M. Myers
President, Westcoast Power Inc.

SERVICES

Vaughn C. Goettler
President and Chief Operating Officer, Union Energy Inc.

Murray P. Birch
President, Westcoast Capital Corporation

Anthony M. Haines
President, [illegible]

Investor Information

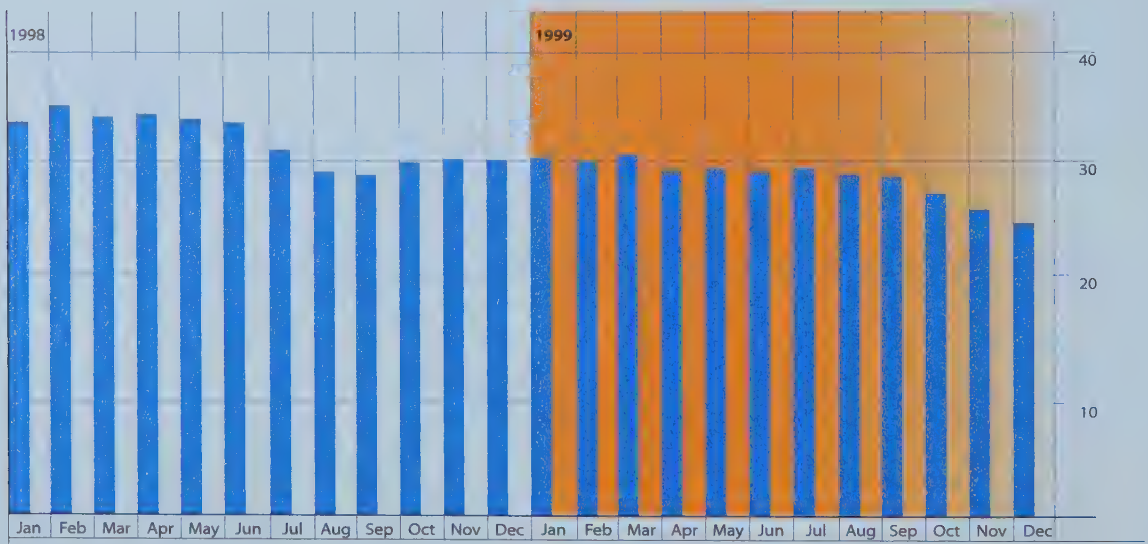
STOCK MARKET PRICE RANGES, EARNINGS, AND DIVIDENDS PER COMMON SHARE

	Toronto ($Cdn)		New York ($US)		Earnings ($Cdn)	Dividends ($Cdn)
	Low	High	Low	High		
1999						
January – March	28.90	31.60	19.00	20.81	1.08	0.32
April – June	27.75	30.05	19.00	20.63	0.05	0.32
July – September	26.75	29.85	18.13	20.06	0.44	0.32
October – December	22.40	28.00	15.19	18.88	0.38	0.32
					1.95	1.28

	Toronto ($Cdn)		New York ($US)		Earnings ($Cdn)	Dividends ($Cdn)
	Low	High	Low	High		
1998						
January – March	31.60	36.35	22.63	25.25	0.99	0.31
April – June	32.55	35.70	22.31	24.94	0.01	0.31
July – September	27.25	33.60	17.56	22.63	(0.06)	0.32
October – December	27.75	31.50	18.00	20.06	0.59	0.32
					1.53	1.26

KEY DATES (tentative)

Quarters 2000	Release of Financial Results	Common Share Dividend Payment Dates
1st Quarter	April 26, 2000	June 30, 2000
2nd Quarter	July 27, 2000	September 30, 2000
3rd Quarter	October 25, 2000	December 31, 2000
4th Quarter	February 21, 2001	March 31, 2001



Monthly Average Share Price

Toronto Stock Exchange (TSE)
($Cdn)

Power Generation

	Capacity	1999 Output
Ford Cogeneration Plant [100%]	35 MW	109,000 MWh
Fort Frances Cogeneration Plant [100%]	110 MW	732,000 MWh
Lake Superior Cogeneration Plant [50%]	110 MW	833,000 MWh
McMahon Cogeneration Plant [50%]	117 MW	847,000 MWh
Whitby Cogeneration Plant [50%]	50 MW	139,000 MWh
Island Cogeneration Project [100%]	250 MW	***
Bayside Power Project [100%]	285 MW	***

International

	Capacity	1999 Output/ Volumes
P.T. Puncakjaya Power [43%]	388 MW	1,654,000 MWh
Shanghai Power Project [32.5%]	50 MW	**
Campeche Natural Gas Compression Services Project [45%]	250 MMcf/d natural gas compression and liquids recovery	***
Cantarell Nitrogen Project [20%]	1,200 MMcf/d nitrogen production 95 km nitrogen pipeline 500 MW	***

Services

Westcoast Energy's energy services businesses – Union Energy [100%], Enlogix [100%], Westcoast Capital [100%], NGX Canada [100%]† and Engage Energy [50%] – act as a key conduit of customer knowledge, offering the opportunity to move the Company's market presence beyond natural gas transportation and distribution.

*	in service Q4 1999
**	expected commercial operation Q2 2000
***	under construction
****	proposed
†	agreement to sell 51% interest in Q1 2000

km	kilometres
Bcf	billion cubic feet
MMcf/d	million cubic feet per day
MW	megawatts
MWh	megawatt hours

Westcoast Energy Inc.
1333 West Georgia Street
Vancouver, British Columbia
Canada V6E 3K9
Telephone: (604) 488-8000
Facsimile: (604) 488-8500
Internet: www.westcoastenergy.com

If you require more information about Westcoast Energy Inc., please contact Corporate Communications at (604) 488-8109.

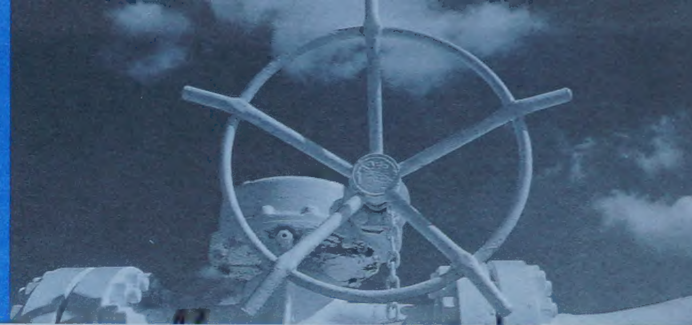
Printed in March 2000

Westcoast Energy Inc.

Fact Book

Information as at December 31, 1999

Westcoast Energy Inc., headquartered in Vancouver, British Columbia, is a leading North American energy company with assets of approximately $12 billion. The Company's interests include natural gas gathering, processing, transmission, storage and distribution, as well as electric power generation, international energy businesses, and financial, information technology and energy services businesses.



Corporate Goal

It is Westcoast Energy's corporate goal to become one of the few big North American energy companies by providing superior energy services value to its customers.

Westcoast Energy At-A-Glance

Total assets	$11.8 billion
Operating revenues	$6,265 million
Net income applicable to common shares	$222 million
Employees	5,648
Natural gas pipelines	53,386 kilometres
Natural gas volumes	3,193 billion cubic feet
Natural gas distribution customers	1.2 million
Natural gas storage capacity	131 billion cubic feet
Natural gas traded	2,226 billion cubic feet
Natural gas marketed	2,037 billion cubic feet
Electric power marketed	10 million megawatt hours
Power generation plant capacity	422 megawatts
Stock symbols	Canada (TSE) – W United States (NYSE) – WE
Shares outstanding	114.8 million
Earnings per common share	$1.95
Dividends per common share	$1.28

Common Shares

Common Shares	1999	1998	1997
Shares outstanding at year-end	**114,847,515**	112,670,767	103,245,876
Toronto Stock Exchange price ranges – high	**$31.60**	$36.35	$33.50
Toronto Stock Exchange price ranges – low	**$22.40**	$27.25	$22.65
Number of common shareholders at year-end	**8,556**	8,645	8,753

Key Dates (tentative)

	Release of financial results	Common share dividend payment dates
1st Quarter	April 26, 2000	June 30, 2000
2nd Quarter	July 27, 2000	September 30, 2000
3rd Quarter	October 25, 2000	December 31, 2000
4th Quarter	February 21, 2001	March 31, 2001

Financial

Operations ($million)	1999	1998	1997
Operating revenues	**6,265**	7,376	7,312
Operating expenses	**5,642**	6,726	6,519
Operating income	**623**	650	793
Other net expenses	**310**	404	432
Income taxes	**46**	48	123
Net income	**267**	198	238
Provision for dividends on preferred shares	**45**	37	28
Net income applicable to common shares	**222**	161	210
Dividends on common shares	**146**	133	122
Operating cash flow	**499**	448	522

Per Common Share (dollars)			
Net income – basic	**$1.95**	$1.53	$2.06
Operating cash flow	**$4.38**	$4.24	$5.10
Dividends	**$1.28**	$1.26	$1.20

Assets ($million)			
Fixed assets	**9,108**	8,569	8,025
Investments	**454**	374	195
Assets from price risk management activities	**186**	—	—
Current assets	**1,677**	1,596	1,574
Deferred charges and other assets	**352**	281	281
Total assets	**11,777**	10,820	10,075

Capitalization ($million)			
Long term debt	**5,550**	5,297	4,941
Liabilities from price risk management activities	**175**	—	—
Preferred shareholders' equity	**865**	716	570
Common shareholders' equity	**2,395**	2,368	2,056
Deferred income taxes	**333**	340	400
Current liabilities	**2,293**	1,935	2,045
Non-controlling interest in subsidiary companies	**166**	164	63
Total equity and liabilities	**11,777**	10,820	10,075

Transmission & Field Services

	System Length	1999 Volumes
BC Pipeline and Field Services Divisions [100%]	5,626 km	670 Bcf
Empire State Pipeline [50%]	252 km	105 Bcf
Foothills Pipe Lines [50%]	1,040 km	1,131 Bcf
Maritimes & Northeast Pipeline [37.5%]	1,110 km	*
Vector Pipeline [30%]	553 km	***
Alliance Pipeline [23.6%]	3,686 km	***
Millennium West Pipeline Project [100%]	75 km	****
Millennium Pipeline Project [21%]	611 km	****

Gas Distribution

	System Length	1999 Volumes	Customers
Union Gas [100%]	34,139 km	1,222 Bcf	1,104,000
Centra Gas British Columbia [100%]	3,386 km	26 Bcf	66,000
Pacific Northern Gas [41% / 100% voting shares]	3,594 km	39 Bcf	39,000

Investor Information

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Westcoast Energy's Dividend Reinvestment and Share Purchase Plan provides registered holders of Westcoast Energy common shares and convertible preferred shares with two convenient and economic ways to increase their holdings in the Company.

Registered shareholders may elect to reinvest the cash dividends paid on all or some of their common and convertible preferred shares in additional common shares of the Company, and are also entitled to make optional cash purchases of common shares through the Plan in amounts from $50 to $5,000 per calendar quarter.

The Plan allows participants to acquire new common shares through the reinvestment of dividends at 95% of the average market price as defined in the Plan. Optional cash purchases are made at the average market price. Participants do not pay any brokerage commissions or other fees on the reinvestment of dividends or the optional cash purchase of new shares through the Plan. All notices and enquiries relating to the Plan should be addressed to the Montreal Trust Company at:

Montreal Trust Company Stock Transfer Services
510 Burrard Street
Vancouver, British Columbia
Canada V6C 3B9
Telephone: (604) 661-0222
Facsimile: (604) 683-3694
Toll Free: (888) 661-5566

SHAREHOLDER AND CORPORATE RELATIONS

Shareholders or others wishing to obtain copies of this Annual Report, quarterly reports, the 2000 Annual Information Form, and other corporate documents should contact the Company either by letter, addressed to the attention of the Corporate Secretary, or by telephone at (604) 488-8000.

Portfolio managers, investment analysts, and other investors requesting financial information respecting the Company should contact:

Thomas M. Merinsky
Manager, Investor Relations
Telephone: (604) 488-8021
Facsimile: (604) 488-8192

All other enquiries by media, the general public, and others respecting the Company should be directed to:

Robert R. Foulkes
Vice President, Corporate Communications
Telephone: (604) 488-8093
Facsimile: (604) 488-8068

STOCK EXCHANGES AND SYMBOLS

Westcoast Energy common shares are listed on the Toronto, New York and Pacific stock exchanges.
In Canada – W
In the United States – WE

Westcoast Energy preferred shares are listed on The Toronto Stock Exchange.
8.08% First Preferred, Series 2 – W.PR.D
4.90% First Preferred, Series 5 – W.PR.F
4.72% First Preferred, Series 6 – W.PR.G
5.50% First Preferred, Series 7 – W.PR.H
5.60% First Preferred, Series 8 – W.PR.J
5.00% First Preferred, Series 9 – W.PR.K

AUDITORS

Ernst & Young LLP
P.O. Box 10101, Pacific Centre
700 West Georgia Street
Vancouver, British Columbia
Canada V7Y 1C7

REGISTRARS AND TRANSFER AGENTS

Common Shares
Montreal Trust Company
Vancouver, Calgary, Regina, Toronto, Montreal

Registrar and Transfer Company
Cranford, New Jersey

Preferred Shares
Montreal Trust Company of Canada
Vancouver, Calgary, Regina, Winnipeg, Toronto, Montreal

REGISTRAR AND TRUSTEE

Debentures
Montreal Trust Company of Canada
Vancouver, Calgary, Regina, Winnipeg, Toronto, Montreal

TAXATION

A resident of the United States receiving investment income generated in Canada is subject to withholding tax under the Income Tax Act of Canada and the Canada-United States Income Tax Convention. With certain exceptions, dividends paid by the Company are subject to withholding tax at a rate of 15%.

Westcoast Energy

WESTCOAST ENERGY INC.

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